CALIFORNIA ENERGY COMMISSION

COMMISSION FINAL REPORT

NATURAL GAS

INFRASTRUCTURE ISSUES

OCTOBER 2001 P200-01-001



Gray Davis, Governor

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PREFACE

The Energy Commission's Electricity and Natural Gas Committee (the Committee) directed the staff to prepare the staff draft Natural Gas Infrastructure Issues report early this year. At that time, natural gas prices were at historically high levels, storage inventories were nearing historic lows, and there were concerns about the ability to both serve the needs of electric generators and store enough gas for this coming winter.

Efforts of the Governor, the State Legislature, regulatory agencies and utilities have lead to the current lower prices and greater availability of natural gas. The Energy Commission cannot, however, stress enough or repeat often enough, the effect that Californians have had on the market through their concerted effort to reduce demand for both natural gas and electricity.

The Energy Commission's report on the natural gas infrastructure provides another piece of the puzzle in a continuing series of informational and analytical publications related to natural gas that began with a 1989 report titled "An Economic Evaluation of Alternative Interstate Pipeline Projects to Serve California," (Energy Commission, March 1989). That report supported the construction of additional interstate pipeline capacity into California based on an evaluation of the existing pipeline system, coupled with the Energy Commission staff's demand analysis. Developers did expand pipeline capacity into California and, as a result, California has enjoyed abundant, low-cost natural gas over the last decade which, in turn, contributed to improved air quality and economic prosperity.

This report makes a significant commitment to the overall understanding of energy interrelationships today, particularly the linkage between natural gas and electricity, and the price of energy resources. It takes advantage of a unique relationship the Energy Commission enjoys with stakeholders—a relationship that will serve as the platform on which future analytic and policy documents can build.

Following release of the Committee draft of this report, several parties asked the Energy Commission to delay adoption of the report so that more detailed comments and critique could be provided. Given the importance of the issues this report addresses, the Committee accommodated these requests. The Committee believes the reader will see the benefits of incorporating the additional information and analysis in the work.

In our 1989 analysis, the Energy Commission reported the benefits of a reliable supply of natural gas to fuel the previously oil-fired power plants and newly constructed cogeneration units. Today, the demand for natural gas by electric generators is, once again, driving much of the expansion of the natural gas

infrastructure. This report concludes that the over 100,000 MW of gas-fired electric generators proposed for construction in the WSCC will require expanded natural gas infrastructure.

As the report further states, under current circumstances, receipt capacity and pipelines are highly cost effective and can be rapidly constructed. By contrast, gas is relatively expensive and experiences volatile swings in price over time. Because of these conditions, the report supports expansion of California receipt capacity, California backbone infrastructure including storage, and interstate pipeline capacity into California.

The Energy Commission is encouraged by interstate pipeline companies' announcements concerning planned expansions and construction of entirely new pipelines, and by the Federal Energy Regulatory Commission's (FERC's) intent to expedite its review of those proposals. The Energy Commission also notes that Southern California Gas Company (SoCal Gas) is constructing 375 MMcfd of additional receipt capacity, which will be online by year-end.

Moreover, at a workshop that FERC Chairman Pat Wood III and Commissioner Nora Brownell held here at the Energy Commission in June, a California Public Utilities Commission (CPUC) witness explained how the CPUC has guided this expansion. The Energy Commission commends both the CPUC and SoCal Gas for their leadership and diligence in expediting the construction of this much-needed receipt capacity.

Finally, based on comments we have recently received on the report, we believe the Energy Commission's position on the role of insufficient receipt capacity needs to be clarified. To that end, the Energy Commission states plainly in this report that insufficient receipt capacity within California and insufficient capacity on the El Paso pipeline system both contributed to the high price of natural gas in the fall and winter of 2000. As a result of the insufficient capacity both to and within California, buyers were less able to force suppliers to bid against each other.

Whether the prices during this period were, in whole or in part, the result of a *free market's* rationing of scarce supplies through a scarcity premium, or entirely the result of price manipulation, is beyond the scope of this report. As noted in the report, the CPUC is currently making its case before FERC that high natural gas prices were due to price manipulation. The Energy Commission has every confidence that the interests of California ratepayers will be well represented by the CPUC.

The Energy Commission does, however, take a strong stand on the main conclusion of the report. California can no longer plan for the future as if we lived in a regulated, cost-plus environment. Under price regulation, adverse

hydroelectric conditions and extreme temperatures did not lead to extreme price spikes. Under today's conditions, that is no longer the case.

California's virtually complete reliance on gas-fired generation to meet its future electricity needs taken together with price deregulation creates a new paradigm. The Energy Commission encourages all participants in the California natural gas market to participate in the reevaluation of the current design criteria for natural gas infrastructure and apply risk analysis to develop design criteria better suited to this new paradigm.

MICHAL C. MOORE Commissioner and Presiding Member Electricity and Natural Gas Committee

EXECUTIVE SUMMARY

SUMMARY

Over the last year, concurrent with the electricity crisis, the natural gas system serving California has been strained in meeting unusually high demand by gasfired electric generators, as well as the residential and commercial heating loads caused by the uncommonly cold November of last year. This problem was reflected in the high natural gas prices California experienced in 2000 and early 2001.

Under the guidance of the CPUC, the California utilities are already moving expeditiously to ensure that intrastate natural gas pipeline expansions are available to meet California's future demand. In addition, the CPUC, Southern California Edison (SCE), SoCal Gas and Pacific Gas & Electric (PG&E) are petitioning FERC to require that interstate pipeline companies ensure that existing capacity remains available to end use shippers serving California. Further, they ask that FERC order that, where necessary, interstate pipelines expand capacity to meet increases in demand. Currently, numerous intrastate, interstate and storage projects are in development. As this report demonstrates, it is essential that these projects deliver natural gas to California end-users unimpeded by upstream demand or bottlenecks.

To this end, the State will need to monitor the natural gas situation closely to provide an early warning of developing problems in time to take actions to prevent shortages, minimize constraints and ameliorate their adverse consequences. These improvements will help to assure that California has adequate supplies of natural gas in both the short- and long-term, as well as to mitigate the high natural gas prices that California has experienced.

Storage levels of natural gas are a key indicator of whether the gas system will be able to meet the summer peaking needs of gas-fired generators, and the winter peaking needs of core residential and commercial customers. In addition, natural gas prices are a key indicator of natural gas infrastructure constraints.

The Energy Commission is recommending that the State take the following actions:

- Analyze the consequences of the increasing upstream gas demands on the El Paso pipeline system as they affect the flows of natural gas and electricity between California and the Southwest United States and Mexico.
- Encourage in-state natural gas production to supplement available natural gas supplies in California through the resolution of gathering system issues and implementation of other incentives.

- Reevaluate and consider developing new design criteria and reliability standards for the State's natural gas system that reflect the changing nature of natural gas demand, especially for electric generators.
- Establish an integrated planning function for the State's natural gas pipeline and storage facilities to identify additions necessary to meet future demand in California.
- Reevaluate and consider developing a natural gas curtailment scheme that emphasizes efficiency and optimizes the use of natural gas during shortage conditions.
- Optimize the use of natural gas storage to better meet the State's natural gas needs, including the investigation of measures to increase noncore customers' use of gas storage.
- Encourage the development of additional independent gas storage facilities in the State.

NATURAL GAS INFRASTRUCTURE

This report addresses four critical infrastructure elements of the natural gas system:

- Natural Gas Supply Active drilling rigs that bring natural gas reserves from underground resource basins to the surface for processing and delivery into the interstate pipeline systems and gathering systems that deliver gas from California production to the intrastate pipeline system.
- Interstate Pipeline Capacity Interstate pipeline capacity to deliver natural
 gas supplies from the remote resource basins to the California border.
- Intrastate Pipeline Capacity Intrastate pipeline systems of California natural gas utilities that deliver gas supplies received at the California border to end-use customers.
- Natural Gas Storage Facilities Natural gas storage facilities from which gas can be withdrawn to supplement natural gas supplies flowing through pipelines at times of peak natural gas demand.

In addition, the report addresses a key driver of recent infrastructure constraints:

The drought experienced throughout the West has reduced the supply of hydro electricity to historically low levels. This reduction has driven the demand for natural gas by electric generators to very high levels, which has in turn strained the natural gas infrastructure.

FINDINGS AND CONCLUSIONS

This report highlights several findings and conclusions regarding natural gas infrastructure. These include:

Natural Gas Supply

Natural gas supplies in North America appear to be sufficient to meet demand in California and the remainder of the United States for the next 50 years, according to the United States Geological Survey.

In contrast to these conclusions, in-state production of natural gas from existing wells has declined over the last decade to about 15 percent of the total State consumption today. Additional production in California could help to meet California's growing demand for natural gas.

Interstate Pipeline Capacity

Upstream demand for natural gas on the interstate pipelines serving California is diverting gas supplies from California. This reduces the effective capacity on the interstate pipeline system serving California. Interstate pipeline capacity expansions will be necessary to meet the level of demand experienced on interstate pipelines in 2000 and early 2001 and to meet expected increases in demand throughout the West. Market forces are currently spurring expansions of these pipelines.

Intrastate Pipeline Capacity

Gas utilities' intrastate pipelines, especially in Southern California, were running at nearly full capacity at times during 2000-2001. This created bottlenecks in delivering supplies from interstate pipelines to gas consumers, including electric generators, in 2000 and early 2001. Under CPUC guidance, SoCal Gas is moving forward with plans to add an additional 375 MMcfd of intrastate pipeline capacity by the end of this year. In addition, PG&E announced plans to add between 200 and 600 MMcfd to its intrastate pipeline system by 2003. Each of these projects when completed will provide greater assurance that adequate natural gas supply will be available in the short-term.

Natural Gas Storage

Gas storage plays an important role in balancing supply and demand, especially during times of peak demand for winter heating needs and, in recent years, for summer peak electricity demand.

Increasing electric generator demand for natural gas in California calls for an integrated assessment of the interactions between the electricity and natural gas markets. The natural gas and electricity markets are becoming increasingly

¹ In September, PG&E withdrew their application to the CPUC for approval of pipeline additions and it is uncertain when these expansions may occur.

intertwined. Major uncertainties exist over how much natural gas California will need in the longer term as a result of in-state versus out-of-state gas-fired power plant development.

The demand for natural gas by existing and new electric generators could continue to stress the natural gas infrastructure in the coming years. Given the high levels of natural gas storage injection since April 2001, PG&E and SoCal Gas have been able to satisfy the peak demand of electric generators this summer, and store enough gas to serve expected core needs at peak during the winter of 2001-2002.

This conclusion is a major departure from the original analysis of summer and winter of 2001 supply and demand that was conducted earlier this year for the May 2001 staff draft report. Several factors contributed to the change in these conclusions including the fact that gas utilities were able to make substantial injections into storage since May, and that conservation efforts helped to dampen summer peak demand.²

Because San Diego Gas and Electric (SDG&E) had curtailments of gas last year, the Energy Commission continues to monitor the situation there. However, the construction of Line 6900 and the pending construction of the Baja Norte pipeline have potentially eliminated the risk of curtailments on that system. SDG&E, which has no underground natural gas storage capability, will need to carefully utilize its pipeline inventory in periods of high demand to minimize the potential curtailment of natural gas deliveries to electric generators in the San Diego area.

Natural Gas Prices

The drought experienced throughout the West has reduced the supply of hydroelectric generation to historically low levels. This reduction has driven the demand for natural gas by electric generators to very high levels, which has in turn strained the natural gas infrastructure. Core demand was likewise higher throughout the State during the winter of 2000-2001 due to colder than average temperature conditions.

This higher demand coupled with inadequate natural gas infrastructure on the SoCal Gas systems that limited the ability of California to receive gas was a factor that contributed to high prices for natural gas experienced in California in late 2000 and early 2001. Inadequate capacity on the El Paso interstate pipeline system to serve both upstream demand and California end users was also a factor.

The extraordinarily high prices during this period appear to be the result of either the competitive market's rationing of supply through a scarcity premium or price

² The updated analysis from the August Electricity & Natural Gas Committee Draft Final Report has been attached to this revised report as Appendix D.

manipulation through the exercise of market power by market participants, or both. In any case, prices would have been lower if the receipt capacity in Southern California had been greater

In addition, the following factors also influenced California gas prices in 2000 and early 2001:

- Large Southern California gas consumers began the winter heating season last year with record low storage inventories.
- California does not currently receive the full amount of firm interstate pipeline capacity for which its shippers have contracted and paid.
- Significant increase in natural gas wellhead prices affected gas prices across the United States.
- Electric generators were relatively indifferent to high natural gas prices as a result of the runaway electricity market in which they could pass through all gas costs to consumers.

These factors would have been exacerbated by the tight infrastructure conditions.

The extent to which the high natural gas prices California experienced in late 2000 and early 2001 were the result of competitive scarcity premiums or price manipulation or some combination of factors is beyond the scope of this report. The CPUC, representing the ratepayers of California, has filed a complaint at the FERC that price manipulation caused by market power is the cause.

The CPUC has also taken steps to reduce the probability of high prices in California in the future by approving SoCal Gas' proposal to remove a total of 37 billion cubic feet (Bcf) of cushion gas from the Montebello, Aliso Canyon and Goleta storage fields. In addition, under CPUC guidance, SoCal Gas is adding 375 MMcfd of receipt capacity to their intrastate pipeline system for this winter. PG&E announced plans to expand its intrastate pipeline system from 200 to 600 MMcfd by 2003. The Energy Commission expects that these and other actions by the CPUC will contribute to more stable natural gas prices.

SPECIFIC ENERGY COMMISSION ACTIONS

This section identifies specific actions the Energy Commission proposes to take to assure adequate tracking of natural gas infrastructure operations, expansions and improvements.

Prepare short- and long-term natural gas supply and demand analyses focused primarily on the Western United States.

- Test current analysis using various assumptions regarding natural gas demand in California, the United States and Canada.
- Identify the ability of the United States and Canadian resources to meet demand.
- Determine wellhead prices necessary to stimulate production to meet demand.
- For interstate pipelines, identify when, where, and how much growth in interstate pipeline capacity will be needed for gas-fired electric generators.
- For California intrastate pipelines, identify when, where, and how much growth in California natural gas utility pipeline capacity and related infrastructure will be needed.
- Modify existing models, and develop additional tools and models as necessary, to explicitly incorporate market conditions into natural gas and electricity supply and demand analysis.

Determine if the market is responding to the natural gas needs that analysis identifies.

- Actively track daily, weekly and monthly:
 - Electric generation natural gas demand in California and the surrounding states.
 - Storage levels for each of the California natural gas utilities and private storage facilities.
- Maintain time lines that identify strategic dates and track progress to ensure:
 - Core storage levels will meet winter demand.
 - Natural gas utility infrastructure additions will be operational for winter needs.
 - Sufficient new interstate pipeline capacity will be operational to meet the projected needs during the next two to three years.
- Prepare risk assessment analysis to determine at what point summer storage withdrawal to meet electricity generation natural gas demand threatens the utility's ability to meet storage targets for core winter needs.
- Alert necessary parties if storage levels begin to slip, infrastructure developments are lagging or other adverse conditions develop.

 Track natural gas resource development on a continental basis, including active drilling rigs and new production coming on line.

On an integrated basis, investigate peak summer and winter natural gas demand periods for the Western System Coordinating Council area.

- Investigate whether pipeline and storage capacities are adequate to meet peak demand periods.
- Prepare the analysis by integrating both natural gas and electricity demand.

RECOMMENDED STATE ACTIONS

Increasing In-State Natural Gas Production

The State should identify barriers to increased in-state gas production and recommend actions to increase in-state gas supplies. In particular, the State should investigate any disincentives that may prevent market participants from expanding in-state production and make necessary changes to eliminate these.

Improving Intrastate Pipeline Systems

California should support expansion of the backbone systems of PG&E and SoCal Gas systems, currently underway or planned, that are in the economic interest of consumers through appropriate cost recovery in ratemaking. Intrastate expansions will help to eliminate bottlenecks and create the slack pipeline capacity that is necessary to promote competition.

The State should establish an integrated planning function for the intrastate gas system to better examine both the short-term and long-term need for system upgrades and improvements.

The State should investigate whether proper incentives, such as appropriate cost recovery, exist to support additional utility investments in intrastate natural gas systems that may be needed to meet future demand growth, and make necessary regulatory changes to eliminate any disincentives that may exist at the State level.

The State should conduct an evaluation of design criteria and reliability standards for planning the intrastate infrastructure, including pipelines and storage facilities. The current design criteria are outdated, focusing primarily on meeting winter peak demands and assuming fuel-switching capability that no longer exists. Growing demand by gas-fired generators has heightened the importance of adequately planning for summer peaking needs.

New design criteria and reliability standards for California utility natural gas systems should be developed that specify a defined level of slack capacity based on the results of the risk assessment and design criteria studies the Energy

Commission plans to undertake to assure adequate slack capacity in the future. These criteria and standards should consider regional conditions at least in the Western System Coordination Council area. Weather conditions that should be explicitly addressed in these criteria and standards include adverse winter peak day needs, summer electric peaking needs and at least 10-year dry hydro conditions. Finally, the criteria and standards should recognize that many noncore customers do not have fuel-switching capability.

Promoting Efficient Gas Use through Changes in Curtailment Rules

The Energy Commission recommends that providing sufficient infrastructure to meet California's need for natural gas to reduce the likelihood of curtailments is the most prudent approach for the State. This process should start with the development and implementation of new planning criteria and reliability standards for the utilities, as outlined above. These criteria and standards should be used as a guide in building and improving the utilities' natural gas systems to better meet demand. If done properly, the chances for curtailments would be minimized.

In the meantime, the State should work with market participants to develop a curtailment policy that is fair and at the same time promotes the efficient use of natural gas in California during periods of limited natural gas availability. While the natural gas system should be designed to provide higher levels of reliability for gas customers, the potential for curtailments cannot be completely eliminated without making improvements to the system that would be questionable from a cost-effectiveness perspective. As a consequence, California needs to be prepared to deal with the potential for natural gas curtailments through policies that promote the most efficient and fair allocation of available natural gas supplies.

Optimizing Noncore Use of Natural Gas Storage

The Energy Commission is concerned about future noncore natural gas storage use, particularly by electric generators. Options that warrant further investigation related to generation reliability, could include the following:

- The Independent System Operator (ISO) could require natural gas storage for Reliability Must Run (RMR) plants to meet annual/seasonal generation requirements.
- The ISO could offer contracts to generators that would allow the recovery of storage costs.
- The Department of Water Resources (DWR) contracts could require storage.
- The Federal Energy Regulatory Commission (FERC) could require storage through its regulatory powers.

- The Energy Commission siting conditions for new power plants could require a level of storage to meet corresponding demand.
- The California Consumer Power and Conservation Financing Authority (CPCFA) could invest in or acquire natural gas storage for electric generation.
- The Energy Commission, the CPUC and FERC could investigate ways to encourage a secondary storage market.
- The CPUC could provide greater incentives to store natural gas by tightening up the utility balancing rules.

The Energy Commission's Electricity & Natural Gas Committee proposes to conduct workshops in its continuing efforts to analyze natural gas issues. All parties are encouraged to participate in upcoming workshops on gas issues so the full range of options, including those outlined above, can be fully explored.

Encouraging More Independent Storage

The State should investigate the prospects for developing additional independent storage facilities throughout California. These facilities should be available to all natural gas customers who would elect to use them. This storage could serve both storage needs for peaking demand for natural gas, as well as storage needs for economic reasons. A secondary storage market should also be promoted. In this manner competition may be encouraged, leading to potentially lower storage costs for all customers.

CHAPTER 1 – INTRODUCTION TO NATURAL GAS INFRASTRUCTURE ISSUES

OVERVIEW

This chapter provides a synopsis of the issues associated with California's natural gas infrastructure on a chapter-by-chapter basis.

Although natural gas supplies have historically been considered abundant in North America, California faces several challenges in assuring sufficient supplies and helping to mitigate episodes of high prices for natural gas in the State. The following discussion outlines the primary issues being faced by California with respect to the key elements of natural gas infrastructure.

PURPOSE OF THE REPORT

The Energy Commission prepared this report as part of its ongoing mandate to assess trends in supply and demand for all forms of energy, including natural gas.³ The Energy Commission is also mandated to carry out studies relating to potential shortages of electrical, natural gas or other sources of energy and to make recommendations to the Governor and Legislature to avert supply emergencies or fuel shortages.⁴

In addition, SB6X (Statutes of 2001) mandates the CPUC, in consultation with the Energy Commission, to report on the present, planned and required future capacity of the State's natural gas transportation and storage system to provide adequate seasonal supplies to customers, including electric generating plants. This report is intended to lay the foundation for additional efforts by the Energy Commission on natural gas issues to meet the SB6X mandates.

BACKGROUND

Chapter 2 addresses important background issues related to gas infrastructure including: deregulation of natural gas markets, increased electric generator demand, uncertainties regarding future in-state electric generation demand and the need for slack capacity on pipelines to support effective competition. In addition, **Chapter 2** presents the Energy Commission's responses to parties' comments received on the staff draft report. The revisions based on these comments were incorporated throughout the report.

³ Public Resources Code Sections 25216, 25309, 25310, 25320

⁴ Public Resource Code Section 25704

NATURAL GAS SUPPLIES

If prices for natural gas are very low for sustained periods, natural gas production can lag behind consumption levels, as economic incentives are insufficient to encourage sustained drilling and production activity. The number of active drilling rigs is a key indicator of whether natural gas production can keep pace with growth in demand.

As discussed in more detail in *Chapter 3*, active drilling rigs in North America gradually increased from 1990 through late 1997, and then declined precipitously in 1998. However, the increases in natural gas prices last summer dramatically increased the number of active drilling rigs. While up to a one- or two-year lead time can exist between the time that drilling rigs are placed in operation and gas wells actually supply gas to the market, increased natural gas production throughout North America is anticipated to keep pace with demand for the foreseeable future.

The production of natural gas supplies in California declined from the mid-1980's, reaching its lowest production levels in 1996. In recent years, in-state production has increased slightly; however it could increase significantly if it could be quickly and efficiently connected to a gathering system. The State should investigate barriers to in-state production and make recommendations to increase these supplies.

INTERSTATE PIPELINE CAPACITY AND EXPANSIONS

When interstate pipelines delivering natural gas supplies from remote production basins are running at or near their full capacity and expansions are not added to keep pace with growing demand, shortages of pipeline capacity can constrain the ability to deliver sufficient gas supplies to California. The interstate pipeline system is addressed in more detail in *Chapter 4* and *Appendix A*.

In addition, when pipeline systems are running at or near their design capacity, little slack capacity exists so that natural gas customers cannot take advantage of the competitive forces that help keep prices down. With slack capacity, natural gas suppliers compete to meet gas customer needs.

Insufficient receipt capacity in California limits the flow of natural gas on interstate pipelines serving California. This past fall and winter, at times, interstate pipelines were full relative to the receipt capacity in Southern California. At those times, even though there was idle interstate pipeline capacity, there was no slack capacity at the Southern California border. At other times, upstream demands reduced the effective capacity on the El Paso system, thereby reducing the amount of natural gas reaching the Southern California border.

Without slack capacity, customers in effect have no opportunity to bargain with competing suppliers on the different interstate gas pipeline systems to get better deals and drive prices lower. These and other factors resulted in California

paying higher prices for natural gas than many other states. The shortage of receipt capacity resulted in either market forces rationing scarce supply through high prices, market manipulation, or a combination of the two factors.

Because California is located at the end of interstate natural gas pipelines, upstream demand for gas threatens the long-term supply of natural gas to California. Increased upstream demand for natural gas includes the proposed addition of several tens of thousand of megawatts of gas-fired electric generation in the Pacific Northwest, the Southwest region and Mexico. It is uncertain how much these additions will displace in-state natural gas-fired generation.

In addition, the demand for natural gas by upstream customers in Nevada, Arizona, and the Pacific Northwest is growing. Because of this demand, several interstate pipelines may not have enough capacity to serve their upstream customers and California at the same time. As an example, population and economic growth by full requirements gas customers in Arizona has already consumed some of the existing pipeline capacity that used to deliver gas to California.

Likewise, economic growth in the Pacific Northwest and cold weather demand have decreased the ability of the interstate pipeline from Canada to deliver to California. In response, the interstate pipeline companies are moving to add pipeline capacity to meet the growing demand on their systems.

While a number of interstate pipeline companies have plans for expanding interstate pipeline capacity, it is unclear at this time whether, and to what extent, electric generators or other gas customers in surrounding states have acquired capacity from these proposed interstate pipeline expansions. As a result, it is difficult to determine whether proposed interstate pipeline capacity additions will increase the overall amount of natural gas supply available to California.

The Energy Commission will continue to monitor the progress of key interstate pipeline projects that would affect delivery capacity to California. These projects are listed in **Table 1-1**.

Table 1-1 Interstate Pipeline Projects

Name	Capacity (MMcfd)	On-line Date
Kern River Pipeline Expansions	135	July 1, 2001
	906	May 2003
Kern/Mojave Pipeline Expansion at Daggett	135	Summer 2001
Kern River High Desert Lateral	282	September 2002
PG&E-GTN Pipeline Expansions	42	November 2001
	169	Summer 2002
	1,000	Within Next 10 Years
Questar Southern Trails Pipeline	90	Spring 2002
	126	Undetermined
El Paso Plains-All American Pipeline	230	Winter 2001
Transwestern Pipeline	150	June 2002
North Baja Pipeline	500	September 2002
Otay Mesa Generating Company Pipeline	110	September 2002
Sonoran Pipeline		
Phase I to CA Border	750	Summer 2003
Phase II in CA	1,500	Undetermined
Ruby Pipeline	750	December 2004
Tuscarora Gas Transmission Company	96	Early 2003
Pipeline		·
Sacramento Valley Project	Undetermined	Undetermined

Source: California Energy Commission

INTRASTATE PIPELINE CAPACITY

The intrastate pipeline systems of California's gas utilities have not been expanded over the last several years to keep pace with growing and/or changing load patterns. Intrastate pipeline capacity issues are addressed in more detail in *Chapter 5*.

Intrastate pipeline capacity, especially in Southern California, constrained the ability of gas utilities to receive natural gas from interstate pipelines at the California border during the fall and winter of 2000-2001. As a result, this limited the ability of gas utilities to deliver natural gas from interstate pipelines to customers throughout their systems. This changed in April 2001 when SoCal Gas announced its intention to expand its receipt capacity. Under the guidance of the CPUC, SoCal Gas is in the process of adding an additional 375 MMcfd to their intrastate pipeline system that will be on line by the end of the year. In addition, PG&E announced plans in April 2001 to add between 200 and 600 MMcfd to its intrastate pipeline system by 2003, and then, in September 2001, withdrew its application. These intrastate capacity additions when completed will help to assure that California has sufficient pipeline capacity to serve its natural gas needs over the next few years.

Until the unprecedented increase in the use of natural gas by electric generators in California in 2000, the mismatch between the capacity of interstate pipelines to deliver gas and the capacity of intrastate pipelines to receive gas did not restrict deliveries to California. In other words, the demand for natural gas was less than the receipt capability and deliveries were sufficient to meet demand at a price that did not include any premiums such as those charged in late 2000 and early 2001.

The proposed expansions of intrastate capacity in California will remove the present bottlenecks and provide California with insurance against shortages and price spikes. The question the State faces is how much additional pipeline capacity does California need in the future to insure that California has adequate supplies of natural gas, and at what price?

The Energy Commission will continue to monitor the progress of key intrastate infrastructure improvements listed in **Table 1-2**.

Table 1-2
Intrastate Pipeline Expansions

intrastate i ipenne Expansions					
Name of Pipeline	Capacity	On-line Date			
	(MMcfd)				
PG&E Intrastate Pipeline Expansions					
Redwood Path (Line 400-401) from Malin	400	Undetermined			
Baja Path (Line 300) from Topock	200	Undetermined			
SoCal Gas Intrastate Pipeline Expansions					
Wheeler Ridge (from Kern/Mojave and PG&E)	85	December 2001			
North Needles (from Transwestern)	50	"			
Receipt for Instate Production in San Joaquin	40	January 2002			
SoCal Gas & SDG&E Line 6900 Expansion	70	June 2001			
Kramer Junction Interconnect	200	December 2001			
SDG&E Intrastate Pipeline Expansion	140-220	Undetermined			

Source: California Energy Commission

NATURAL GAS STORAGE FACILITIES

Natural gas from storage is used to supplement supply flowing through pipelines when demand is high. If sufficient natural gas is not injected into storage facilities during periods of low demand, stored gas cannot be used to supplement deliveries of natural gas from interstate pipelines to meet higher peak demands as described in *Chapter 6*.

Because of expected high demand for natural gas in the spring and early summer of 2001, the Energy Commission was concerned that natural gas utilities would not be able to inject sufficient natural gas into storage to carry California customers through next winter's peak heating demand season. In addition, if electric generators and industrial customers did not place gas into storage before the summer electric peaking season, curtailments of natural gas supplies for these loads were expected to exacerbate electricity shortage conditions and lead to additional blackouts.

However, as a result of favorable conditions in spring and early summer, many of these fears have been alleviated. All storage facility operators in California have been injecting at, or near, maximum injection capacity since March 2001. All sectors are actively participating in placing natural gas into storage. The result is that storage levels are very healthy.

Plans are underway to increase the storage capacity of utility and private natural gas storage facilities. The Energy Commission will continue to monitor the progress of proposed storage expansions listed in **Table 1-3**.

Table 1-3
Gas Storage Facility Expansions

Storage Facility Name	Capacity	On-line Date
PG&E McDonald Island Storage Expansion	400-600	Undetermined
	MMcfd*	
SoCal Gas Modifications to Aliso Canyon and La		
Goleta Storage Facilities	14 Bcf	Winter 2001-02
SoCal Gas Montebello Abandonment (over next 5	12 Bcf*	July 2001
years).		·
Wild Goose Storage Facility	29 Bcf	Undetermined
Lodi Storage Facility	12 Bcf	December 2002

*Increase in withdrawal rate.

Source: California Energy Commission

NATURAL GAS PRICES

Insufficient natural gas infrastructure at the wellhead, on interstate pipelines, on intrastate pipelines or on storage facilities contributes to higher natural gas prices, as discussed in *Chapter 7*. When the supply is less than demand, prices almost always rise due to market forces. Market participants may attempt to manipulate prices even higher than market conditions warrant. Expanding the natural gas infrastructure will reduce prices caused by both supply constraints and any market manipulation that might exist.

The Energy Commission will continue to monitor gas prices and conduct analyses to determine the extent of natural gas infrastructure improvements that could reduce high natural gas prices and assure that, in the long term, gas price spikes could be dampened or avoided altogether.

CHAPTER 2 – BACKGROUND

INTRODUCTION

The following chapter provides background information that is necessary to understand more fully the natural gas infrastructure challenges that California faces. This chapter also presents the Energy Commission's responses to parties' comments, which have been incorporated throughout this report.

Over the past 20 years, California has increasingly relied on natural gas as a major energy supply source. As a result of abundant supplies, low prices, and the air quality benefits of natural gas compared to other fuels, many residential, commercial and industrial users have switched, where possible, to gas. Electric generation that was fueled primarily by oil in the 1970's has also been converted to burn natural gas. New power plants proposed or under construction throughout the West are primarily natural gas-fired generators.

In addition, the dramatic growth in electric generator use of natural gas forced the utilities to operate at or near capacity limits last summer. Under the guidance of the CPUC, SoCal Gas has responded by starting construction on 375 MMcfd of additional intrastate receipt capacity, expected to be on-line by the end of 2001. The intrastate pipeline expansions by SoCal Gas should help California to adequately meet its demand for natural gas and help to put downward pressure on natural gas prices.

Until the summer of 2000, natural gas prices were extremely attractive in California and throughout the United States. However, natural gas prices rose dramatically beginning in the summer of 2000 as prices in the electricity market spiked to extremely high levels. California consumers, who buy in the spot market, or under contracts indexed to the spot price, have paid some of the highest natural gas prices in the continental United States.

NATURAL GAS UTILITY SYSTEMS

Natural gas systems have historically been designed to meet peak natural gas demand for core (residential and commercial) customers in the winter. California's increasing reliance on natural gas for electric generators highlights the importance of adequately accommodating summer peak demand in planning future gas infrastructure. The PG&E⁵ and SoCal Gas⁶ systems are designed to

⁵ PG&E uses a combination of an abnormal peak day and a cold winter day criteria for its system design. The abnormal peak day is the coldest systemwide temperature of 31 degrees that is expected to be reached or exceeded for one day in 40 years. A cold winter day is based on a series of three to four cold days of about 38 degrees that is expected to occur every five years.

⁶ SoCal Gas uses a cold weather criteria based on a systemwide temperature of 38 degrees that has a probability of occurrence of once in every 35 years.

meet cold weather criteria, which are based on historic weather conditions. These criteria determine the amount of intrastate infrastructure for each utility; this includes the pipelines, compressors, and storage that are necessary to maintain service to core customers during peak winter natural gas demand.

If the natural gas system were to meet the needs of all customers on the peak cold winter day, then the system would need to have at least twice the pipeline capacity it has now. This is not economically feasible since the historic coldest day occurs only rarely. Thus, the current design criteria allow that not all customers will be served on the peak cold winter day.

But the physical nature of natural gas allows flexibility in operating the pipelines and storage facilities in the system to balance supply and demand. If deliveries from the interstate suppliers exceed demand, gas can be stored. Gas storage can be accomplished in the distribution utility pipelines by increasing the pressure in the pipeline system to temporarily increase the amount of gas the pipeline can hold. Storage can also be accomplished by injecting gas into underground storage facilities. Conversely, if the demand exceeds supply that demand can be met by decreasing pressure in the pipeline or by removing gas from storage.

If gas utilities cannot meet the needs of core residential and commercial customers by withdrawing from storage, they will then curtail or divert gas from noncore customers. This could occur any time of the year. In California, the natural gas system was originally designed on the assumption that large industrial and electric generating customers have dual fuel capability. In the event of a natural gas curtailment or diversion, the dual fueled customers would switch to oil and, as a result, be able to maintain operations. In this way (curtailment or diversion of noncore customers instead of core customers), the impacts of natural gas supply shortages would be minimized.

For most of the 1990's, the natural gas system had surplus capacity, and diversions/curtailments were rare. At the same time, more stringent air regulations during this period caused most dual fueled customers to abandon their oil burning capability. Now that supply and demand is more in balance, diversions and curtailments of noncore customers are more likely to occur in accordance with the design of the current system.

If California continues to rely on the current design criteria for the natural gas system to meet peak winter demand, California faces an increasing chance of electric generator curtailments during unusually cold winter conditions, as well as in summer severe heat conditions. If the total demand for natural gas by all customers, including electric generators and industrial facilities, exceeds intrastate pipeline systems capacity, then curtailments of natural gas to generators under current curtailment rules could exacerbate electricity supply problems.

THE MOVE TO COMPETITION IN NATURAL GAS MARKETS

Over the last 20 years, the interstate and intrastate natural gas market has evolved from one that was completely regulated to one that is primarily competitive in structure.

Before 1984, the interstate pipeline purchased gas at the wellhead and delivered it to the California border. The California gas utility then bought the gas from the interstate pipeline and sold it to the retail customer. Originally, all interstate pipelines stopped at the California border and delivered gas to either a PG&E or SoCal Gas intrastate pipeline. The SDG&E system received its gas from SoCal Gas. The three California gas utilities would then resell the gas to consumers. No gas consumer in the State could buy natural gas from any entity other than the three gas utilities. The only exceptions were companies that could be directly linked to gas fields in California; a practice that continues today.

In 1984, the FERC took the first step toward addressing pipeline competition with an order eliminating a requirement that utilities purchase natural gas from interstate pipelines. FERC Orders 436 and 500 required interstate pipelines to provide nondiscriminatory service to all transporters of natural gas. Today, transporters, including gas marketers and large-end users, buy the gas at the wellhead, arrange to ship it to California, and then sell or use it in California.

At the State level, the CPUC ended the obligation of California natural gas utilities to purchase and supply gas to all customers. To protect the residential and small commercial customers, the CPUC created the concept of core customers. To meet the service needs of these core customers, the gas utilities set aside an amount of intrastate pipeline capacity that varies by pipeline and season. In addition, the gas utilities reserve space on the interstate pipelines to serve the core customer needs.

With the move to competition, the natural gas utilities are no longer responsible for assuring sufficient supplies on interstate pipeline for noncore natural gas customers; noncore customers include commercial customers and electric generators. These noncore customers are now responsible for acquiring upstream pipeline capacity, or interstate pipeline capacity. The gas utilities, however, are responsible for assuring that the backbone pipeline system, the intrastate system, is adequate to receive the flow from the interstate pipelines.

INCREASED NEAR-TERM NATURAL GAS DEMANDS FOR ELECTRIC GENERATION

During the summer of 2000, dramatic increases in the use of natural gas for electricity generation in California taxed the natural gas system's ability to deliver sufficient natural gas supplies. Construction plans for electric generators fueled by natural gas will pose increasing demands for natural gas throughout the western states and Mexico. Increased electric generation in California will place additional pressure on the gas utilities' systems to meet demand.

In California, the events in 2000 and potential problems identified for the natural gas and electricity systems demonstrate the increasingly interconnected nature of California electricity and natural gas markets. Both markets have been partially deregulated and are subject to price spikes whenever capacity limits are approached. These changing circumstances of natural gas demand need to be explicitly addressed. The current events in electricity and natural gas markets are calling into question the prudence of relying totally on the market to plan for the State's need for natural gas supplies and infrastructure to serve electric generators.

In addition, the existing natural gas curtailment policies for PG&E and SoCal Gas call for a pro-rata reduction in natural gas supplies to all noncore customers, electric generators and industrial customers alike. The curtailment of natural gas supplies to electric generators could exacerbate rolling blackouts at times when electric generation capacity is short. At the same time, the curtailment of industrial customers could increase the economic impacts from lost production that industrial customers are likely to bear because of electricity outages. The State should examine changes to curtailment rules that would minimize disruptions of electric generation and industrial operations.

In the long term, the Energy Commission believes that the current CPUC requirement that under high demand conditions only the core needs are to be met should be re-evaluated. The appropriate level of reliable natural gas service provided by the gas utility needs to be examined in light of the fact that large noncore customers no longer have alternative fuel capabilities due to both economics and environmental regulations.

In this new environment, the natural gas utilities need to be capable of delivering natural gas to meet noncore demand during the high demand periods. New planning tools, criteria and processes to implement additions of pipeline capacity and storage are needed to insure that a utility will have the necessary facilities to meet core needs, and those of noncore customers who wish to be supplied during peak day, month and year conditions.

MEETING THE LONG-TERM NEEDS OF ELECTRIC GENERATORS

As stated earlier, it has not been economical, under the current design criteria, for the intrastate gas system to build sufficient pipeline or storage capacity to avoid curtailing noncore customers, including electric generators, during periods of high peak natural gas demand. This may not be true in the future because there are limited alternatives to burning gas.

Electric generators also affect other natural gas customers when they decide whether or not to place gas in storage. All customers will benefit through lower gas prices and greater reliability of gas service if electric generators store gas to

meet their needs during peak demand periods. Currently, there is no requirement for electric generators to store gas or to participate in gas storage programs. Inadequate supply planning by electric generators causes higher prices, for both natural gas and electricity, for all customers. Insuring reliable gas supply for electric generators will require sufficient capacity to meet their needs in adverse conditions.

Some measures have been designed into the natural gas system that allow some noncore customer demand to be met during peak demand periods. For example, gas systems can continue to serve customers even though demand exceeds the flow of gas being delivered to the system at that moment in time. The gas system can draw on "gas packed" in its pipeline system or can draw on storage. However, these are temporary measures and cannot be sustained for extended periods of time.

In Northern California, customers such as industrial gas users and electric generators are all considered noncore customers and have less reliable service by definition than core customers. The noncore customers use the capacity that is left after the core and off-system transportation⁷ capacities are subtracted from the PG&E backbone capacity⁸. The remaining capacity is available for marketers and qualified customers under a CPUC-approved tariff to ship natural gas. There are various levels of service that may be selected. The selection includes rights to a specific backbone path for direct delivery to the end use point. These capacity rights are tradable in a secondary market.

In Southern California, industrial customers and electric generators can select different levels of service from "firm" to "interruptible" service. However, the shipper has no specific backbone rights or choice about which of SoCal Gas's backbone pipelines it may receive its gas through. There is no secondary transport market in the SoCal Gas system. The CPUC is presently considering several proposals to switch SoCal Gas to a system similar to that utilized by PG&E.

Gas utilities can reserve capacity for the residential and commercial core customers indefinitely with little risk. The utility knows that, as a whole, core customers will continue to demand a fairly constant amount of natural gas. This relative predictability in demand allows them to adequately plan to meet the needs of the core customers indefinitely.

Before the summer of 2000, natural gas marketers and noncore customers who were buying their own natural gas supplies under market conditions were less

⁷ Off system transportation is the shipping of non-utility owned gas by a utility to another utility system.

⁸ The backbone system of the gas utilities consists of pipelines for gas transmission, but not for distribution.

likely to take a long-term view of the future. Consequently, they were unlikely to commit to very long-term payments for capacity on pipelines as short-term purchases offered cost savings. This lack of long-term commitment has consequences for California.

California is at the end of the pipeline system, and its suppliers may not have contracted for firm capacity for all of the State's needs. Or, if the price is right, the market participants with pipeline capacity may elect to sell their gas supply before it gets to California. To do so may violate their California customers' contract rights. This means that either the marketer has to make up the gas from another source or potentially pay contract penalties to its customers. As a result, whenever the upstream demand increases, California may lose flowing supply. Gas consumers, particularly electric generators, appear to have responded to this fact by bidding for capacity on all the recent interstate pipeline expansions to secure sufficient capacity for their needs.

Because electricity and natural gas markets are increasingly intertwined, California must consider an integrated approach to planning for natural gas capacity to assure all critical natural gas demand, including electric generators, can be met in the future.

TRADE-OFF BETWEEN IN-STATE AND OUT-OF-STATE NATURAL GAS USE FOR ELECTRIC GENERATION

One of the difficulties in assessing future infrastructure needs for natural gas-fired power plants in California is the relationship between available interstate pipeline capacity and power generation needs upstream of the California border. Natural gas power plants in surrounding states that sell electricity into California theoretically displace natural gas-fired power plants in California. Therefore, the increase in upstream power plant demand may reduce the need for increased pipeline capacity to meet a lower natural gas demand for electric generation within California. However, the gas-fired plants in other states may threaten interstate capacity to California.

Table 2-1
Proposed Power Plants (MW)

Status	No. West	So. West	Rocky	Cal/Mex	Total
			Mtn		
Under Construction/Complete	5,313	9,141	552	8,771	23,777
Approved	3,376	2,256	1,327	4,926	12,185
Applications Under Review	8,174	12,166	1,215	9,647	31,202
Starting Application Process	6,928	30	1,080	10,205	18,243
Press Release Only	2,752	7,530	2,391	3,491	16,164
Total	26,843	31,123	6,565	37,040	101,571

Source: California Energy Commission website updated June 19, 2001

Table 2-1 shows power plants proposed for construction throughout the Western states. Many gas-fired power plants are proposed, or under development, in

Nevada and Arizona. These plants, if constructed in excess of the needs of Nevada and Arizona, may export their electricity into Southern California. These imports could displace some of the natural gas usage on the SoCal Gas system and reduce the need for expanding the intrastate system to meet gas-fired generator demand.

It is uncertain how new electric generation for Baja Mexico at Rosarito will impact the natural gas demand and electricity generation mix. Because Baja Mexico already has several hundred megawatts of older inefficient gas-fired generators, Mexico will not immediately need the entire output of the proposed 550 megawatts (MW) of generating capacity. Natural gas demand in Mexico could actually decrease as this new highly efficient combined cycle unit displaces the older inefficient steam units.

On the other hand, Mexico may elect to sell electricity to California. If so, it could run its older units, increasing gas demand in Mexico. In that instance, electric generation on the SDG&E system, or elsewhere in California, could be displaced, thereby reducing gas demand in San Diego or other areas of the State.

The Pacific Northwest also has ambitious construction plans for gas-fired power plants that may be considered surplus to their native electric loads. As a result, additional imports of electricity from the Pacific Northwest may be available to California. These imports could further displace gas-fired generators in California in the future.

NEED FOR "SLACK CAPACITY" ON INTERSTATE AND INTRASTATE PIPELINE SYSTEM

Slack capacity is defined as the amount of pipeline capacity that is in excess of the natural gas demand that is needed to generate the benefits of competition. There is no slack capacity when natural gas demand is equal to the amount of pipeline capacity available to deliver gas into the State through interstate pipelines or to deliver to customers on the intrastate pipeline system. When there is no slack capacity, customers lose the benefits of competition, and prices increase overall or spike upward.

As a rule of thumb, price competition for pipeline capacity prevails when pipelines operate with sufficient slack capacity to allow customers to bargain with alternative pipeline suppliers. Once slack capacity is reduced, a premium starts to creep into the market, as market forces will cause prices to increase to ration scarce supply. At minimum levels of slack capacity, those who hold capacity can exercise market power and, therefore, can arguably control prices. As the system loses virtually all of its slack capacity, price spikes appear.

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⁹ CPUC Decision 97-08-055.

This situation existed on the El Paso system and in California in late 2000 and early 2001. Since the El Paso and State's gas utilities were generally short of slack capacity, this situation contributed to natural gas price increases in 2000 and early 2001, as well as to occasional very high spikes. Market participants may have taken advantage of the absence of slack capacity to manipulate gas prices higher than is justified by supply and demand conditions. Given the cost to consumers, the State needs to recognize the role played by the natural gasfired generators in causing strains on the natural gas utility pipeline system and take steps to minimize the likelihood of a repeat of this past episode of high natural gas prices.

California should support cost-justified expansion on the gas utility backbone systems to meet future demand, as well as to provide for slack capacity that mitigates price impacts as discussed in *Chapter 6*.

First, slack capacity is needed in conjunction with storage to insure sufficient pipeline capacity to meet peak demand that California natural gas customers have for natural gas (daily, monthly and annual). Second, from California's experience in 2000 (when demand was high and capacity was short), the lack of competition caused commodity prices to exceed what would be considered normal levels for the circumstances. Having 15 to 20 percent slack capacity last year would have been more than paid for through reduced commodity prices.

To promote higher levels of slack capacity, new design criteria and standards of reliability for the natural gas companies will be required. These should include the capacity to receive natural gas from storage. Whether slack capacity needs should be based on a dry year, adverse cold day criteria, or a combination of these and other factors should be determined by assessing the various risks associated with the occurrence of these extreme events. In comments on the draft report, several parties favored using dry hydro conditions ranging from a 10-year dry hydro year to conditions similar to the past two years.

The Energy Commission recommends that stakeholders work with the Energy Commission in its efforts to analyze new design criteria and reliability standards for California natural gas utilities. These criteria and standards should consider regional conditions in the Western States Coordination Council area. They should also account for weather conditions including adverse winter peak day needs, extreme hot summer peak day needs, and at least 10-year dry hydro conditions. Finally, the standards should recognize that many noncore customers do not have alternative fuel back-up capability. The Energy Commission proposes to conduct risk assessment and other analyses that should be used as a basis for revisions to design criteria and reliability standards for the State's natural gas system.

When considering whether to invest in capacity expansion in their utility systems to add slack capacity, one of the primary concerns of the utility is whether they

can recover their costs for backbone expansions in rates. A regulatory approach that encourages such investment to assure slack capacity can mitigate or prevent price spikes and overall price increases, such as those California has experienced.

To a large extent, the issues regarding expanding capacity on the intrastate backbone gas system is a question of recovery of investment, and the willingness of the various shippers to support expansion. However, these decisions need to be put in perspective. The reality of today's gas market is that pipelines are cheap and gas is expensive. From a public interest standpoint, it is better to put in slack capacity and to pay a few cents more for transportation than to pay dimes or dollars more for gas supplies.

RESPONSE TO THE PARTIES COMMENTS

The Energy Commission has responded to the broad natural gas infrastructure issues raised by parties in this proceeding in the following section. They have been grouped by the following topics:

- Natural gas infrastructure improvements,
- Natural gas storage issues,
- Electricity and natural gas storage analysis,
- Planning and design criteria,
- Efficiency curtailment scheme, and
- In-state natural gas production.

In addition, Appendix C summarizes the major comments of parties related to these topics made in either written or verbal testimony. Minor corrections and updates of information presented in parties' comments have been incorporated in the body of the report. Other changes to the report reflect the responses to parties' comments discussed below.

The Energy Commission wishes to thank the numerous parties, including the FERC, PG&E, Calpine Corp., Wild Goose Storage Facility, California Generation Coalition, Duke Energy, and California Independent Petroleum Producers (CIPA), that support the Energy Commission's efforts to examine natural gas infrastructure issues and that support the report's overall assessment of natural gas issues facing the State. These parties generally noted that providing sufficient inter- and intra-state gas infrastructure would greatly influence the

¹⁰ A number of gas marketers and electric generators have commented that SoCal Gas should remove the bottlenecks on its backbone system and allow for a free flow of natural gas into southern California.

State's future ability to acquire and deliver sufficient natural gas supplies, at reasonable costs, to meet California's growing demand for natural gas. These comments further highlight the need identified in this report for expanded interstate pipeline capacity, as well as expanded intrastate pipeline and storage capacity.

Natural Gas Infrastructure Improvements

The parties generally agree that improvements in interstate and intrastate natural gas infrastructure will help to assure sufficient natural gas supplies to meet growing natural gas demand in the state and mitigate the high prices California has paid for natural gas supplies. Most parties also agree that the recent growth in natural gas demand by electric generators in California is a driving force behind current constraints on the natural gas system. However, there is considerable debate among the parties as to whether the natural gas demand by these generators will continue in an upward trend or whether current gas demand is a temporary phenomenon related to drought conditions throughout the West. The question of natural gas demand for electric generators is addressed in a later section.

Many parties note, as does the staff in the draft report, that the market appears to be responding appropriately to current system constraints through the numerous proposals to add significant pipeline capacity on the interstate and intrastate systems. The utilities, including PG&E and SoCal Gas, appear to support the use and expansion of existing intrastate facilities to best serve the needs of California consumers. Other market participants appear to support the use and expansion of pipelines and infrastructure outside of the utilities' systems.

The Energy Commission believes that a mixture of utility and private, or so-called "bypass", infrastructure investments will help to provide the necessary intrastate and interstate pipeline capacity to meet California's future demand for natural gas. The Energy Commission continues to believe that monitoring the progress of the numerous pipeline expansion projects currently underway on the interstate and intrastate systems will be needed to assure that they come on-line as planned and are available to meet the growing demand for natural gas, in particular, the natural gas demand for electric generators. Through this monitoring, the Energy Commission can serve as an early warning system for State government if pipeline expansions appear to lag behind growth in natural gas demand, and State actions become warranted.

In its later comments on the Commission's report, Sempra notes that SoCal Gas utilization rates for its backbone pipeline system averaged 96.5 percent in June/July when prices moderated, about the same as seen during the high-priced period of September 2000 through May 2001. This is used as an argument to counter the Energy Commission's conclusion that inadequate intrastate infrastructure contributed to high gas prices.

The Energy Commission notes an important difference in the pipeline utilization and associated price impacts during the periods noted by Sempra. During winter periods the pipelines were full of flowing gas to meet demand. In contrast, in the June and July 2001 period that Sempra notes, the pipelines were being used to meet both flowing demand as well as to carry substantial amounts of natural gas for injection into storage. When pipelines are full with flowing gas, loads, especially electric generators during periods of high electric demand, do not have the option to defer their demand to a later date. In contrast, when pipelines are full to accommodate gas for injection into storage, that injection can be deferred to a later date freeing up space in the pipelines to flow additional gas to meet natural gas demand on the system. Injecting gas into storage tends to have a moderating influence on gas prices.

The Solar Development Cooperative (SDC) provided comments on the staff draft report that were inadvertently omitted from the August, 2001 Committee Draft Final Report. SDC comments that fossil fuel market participants do not need any incentives for infrastructure to deploy their technology. SDC recommends that the Energy Commission assure competitive manufacturing opportunities and rapidly increased production of building-integrated photovoltaics and fuel cell products immediately. The Energy Commission agrees that alternative technologies have an important role to play in meeting California's energy challenges and is committed to their development through its Public Interest Energy Research and other technology programs.

Natural Gas Storage Issues

Parties generally agree on the important role that natural gas storage plays in meeting peak demands on the system and in mitigating natural gas price spikes. As noted by Wild Goose, an additional benefit of storage is that it provides a secure supply that cannot be "bought away" by upstream markets, such as Midwest and Northwest customers. In addition, they note that use of storage can improve the transmission load factors on gas utility pipelines that benefit all customers through a reduction in transmission costs.

Parties, including Calpine and Wild Goose, agree that it appeared last year that electric generators and noncore customers did not fully utilize storage that was available to them. The parties noted that these customers were responding to price signals when they sold off gas that could have been stored. They did so because, at the time, it seemed that the prices in the future, that winter, would be lower and they would be able to buy back gas at less cost.

Most parties believe the current behavior of generators and noncore customers (increasing gas in storage) demonstrates that these customers have learned an important lesson. While the Energy Commission is encouraged by market participants' efforts to better utilize storage, we are not convinced that the mistakes from last year will not be repeated in the future. The Energy Commission notes that lessons learned can be quickly forgotten as market

dynamics change. Consequently, the Energy Commission believes that a continuing examination of how to maximize storage is warranted.

The staff draft report recommended that the Energy Commission and the CPUC investigate rebundling each gas utility's noncore storage function. The staff suggested that doing so could allow the utilities to more optimally use its entire storage inventory to meet peak needs and allocate re-bundled storage costs to all customer classes.

This proposal was rejected by all parties, including market participants, utilities, and independent storage developers. In rejecting the proposal, parties claim that the need for rebundled storage is predicated on a concern that generators and noncore customers will repeat the mistakes of 2000 by not fully injecting gas into storage. Most of the comments highlight several activities that suggest that the generators and noncore customers' injection behavior is different in summer 2001 and will continue to be different in the future:

- Noncore customers are injecting gas into storage, while total storage is on par with the five-year average (Sempra comment).
- Generators are making significant storage investments by obtaining storage capacity in open seasons and signing up for new firm pipeline capacity (Calpine comment).
- The electricity industry is rapidly moving to the use of long-term energy arrangements rather than purchasing power on the spot market. Long-term contracts encourage more generators to use storage (PG&E comment). Bilateral storage arrangements with generators should also be supported (Duke comment).

In addition to the market implications noted above, PG&E highlights the legal implications of rebundling storage. The Energy Commission acknowledges the point that the CPUC cannot order generators or other noncore customers to store natural gas.

The Energy Commission agrees that the market appears to be responding to the call for added injection at the current time. However, we are still concerned about whether the market can be relied upon to maximize the use of storage in the future. The Energy Commission also agrees with parties that rebundling at this time may not be the most effective means of increasing utilization of storage, and it is inconsistent with the direction the gas industry has been moving toward in recent years in increasingly relying on competition. Therefore, the Energy Commission has withdrawn the proposal to rebundle storage services.

To further consider the storage issue, the Energy Commission intends to hold a workshop to obtain additional input regarding how regulators and decision-makers can optimize the use of storage (both utility-owned and independent) in the future. We will consider, as part of the workshop, whether reducing the

flexibility of utility balancing rules will send correct signals to encourage customers to use storage, as Wild Goose suggests in its comments. We will also consider other potential disincentives to utilizing storage and potential incentives to maximize the use of storage in California.

Electricity and Natural Gas Storage Analysis

Most parties agree that upstream demand for natural gas, and the amount of natural gas for electric generators in-state versus out-of-state, are important uncertainties in assessing whether future gas supplies will be adequate to meet demand. Sempra, on behalf of SoCal Gas, argued that the unprecedented demand for natural gas by electric generators in 2000 represented an anomaly due to drought and other unusual weather conditions. They maintain that as older less efficient electric generators are replaced with more efficient new generators, the demand for natural gas for electricity generation would level out, or even decline, in the future. PG&E notes that the staff's analysis was focused on the short-term and that beyond 2002 there is much more uncertainty about electricity demand for natural gas.

The Energy Commission agrees that there is substantial uncertainty regarding natural gas demand for electric generators in California and throughout the West in the future. The Energy Commission believes that a more integrated approach to analysis of electricity and natural gas market interactions throughout the West, as suggested in the staff draft report, is warranted. The Energy Commission will continue to assess future supply, demand and infrastructure issues associated with natural gas and electricity markets in the mid- to long-term.

Sempra suggested in its comments on the Energy Commission's report that their biggest challenge in forecasting the short-term needs of the SoCal Gas system is the unpredictability of noncore natural gas demand. They state that this is because electric generators have so many choices in where to hook up and what kind of gas service they can acquire. Sempra argues that the problem with uncertainty about electric generator demand can be avoided if noncore customers, particularly electric generators, were required to sign up for long-term firm commitments for 15 years on the intrastate utility systems.

In response to Sempra's recommendation that noncore customers, particularly electric generators, be required to make long-term commitments, the Independent Energy Producers (IEP) and DENA provided comments regarding the severe consequences this recommendation could have on the competitiveness of both the natural gas and electricity markets.

The Energy Commission notes that long-term firm commitments are an attractive way to hedge against future uncertainty, but there may also be value in maintaining a spot market to promote competition. The Energy Commission believes that further study is needed to determine whether a requirement that all electric generators sign long term commitments would be inconsistent with a

competitive market for either electricity or natural gas. Certainly this issue deserves further consideration and discussion among the various affected parties because of its far-ranging impacts. The Energy Commission believes that, at this time, the issue of long-term commitments for noncore customers is beyond the scope of this report.

Sempra also presented updated storage figures that they believe will mean that SoCal Gas is highly unlikely to face curtailments to meet peak demand this year, and that storage targets for core customers for the winter will also be met. The analysis of SoCal Gas and PG&E electricity demand and storage levels has been updated in the Energy Commission's report to reflect the new storage levels, as well as other clarifying information on the SDG&E system, provided by Sempra.¹¹ Current high storage levels for the gas utilities are such that no problems in meeting winter peaking demand are anticipated at this time.

Planning and Design Criteria

The Energy Commission received written and verbal comments from numerous parties supporting the need to reexamine the design criteria for the intrastate gas infrastructure system. Many parties agree with the staff conclusion that the changing nature of demand for natural gas, primarily driven by increasing demand by electric generators during the summer peak demand season, needs to be explicitly incorporated in the planning and design criteria for the natural gas system.

Several parties – including Calpine, Duke, PG&E and Sempra – note that the lack of back-up fuel by noncore customers originally assumed in planning and design criteria for the natural gas system represents a significant change that needs to be recognized. In addition, these parties suggest that dry hydro conditions should be included in revisions to the planning and design criteria. Duke notes that even though extremely low hydro conditions, in California and the Pacific Northwest combined, have a very low probability of occurrence, they have extremely negative consequences.

Duke suggests establishing a firm reliability standard for the utilities' natural gas systems of 1 in 10 years, with utilities authorized to pursue projects consistent with this standard, and assurances of rate recovery. PG&E also suggests a reliability standard of 1 in 10 year probability of diversion for noncore customers and that the core should be required to hold contracts for gas transportation and storage to satisfy a 1 day in 10 year cold event to reduce reliance on diversions from noncore customers. Duke recommends adopting additional planning criteria based on adverse hydro conditions, along with a 1 in 35 year standard for core customers.

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¹¹ In this revised report the analysis of summer electric demand and storage levels has been presented in Appendix D for information purposes.

The parties generally supported the idea of planning for slack capacity in the intrastate pipeline system to allow for gas-on-gas competition. The parties did not have specific recommendations for the exact level of slack capacity that should be planned for in the natural gas system. Some parties suggested that the market should determine the amount of slack capacity. Others suggested that the current 15 to 20 percent slack criteria adopted by the CPUC, and supported by the Energy Commission in the 1990's, should be relied on.¹²

The Energy Commission agrees that reliability planning for the natural gas system has merit (based on adverse hydro conditions, and designed to reduce diversion of noncore customers). In addition, the Energy Commission continues to support the idea of including a slack factor in planning for the State's intrastate infrastructure needs. The Energy Commission plans to conduct additional risk analysis to develop more concrete recommendations on planning and design criteria for the State's natural gas system.

Efficiency Curtailment Scheme

The staff draft report suggested that an efficiency curtailment rule would be preferable to the current pro-rata curtailment policy used by gas utilities. Sempra suggested that it would be difficult to design such a curtailment policy to account for the different efficiencies of peak versus base load generators, and such a policy may not lead to greater electric reliability. They maintain that the current pro-rata is fairer. Duke commented that expanding and upgrading of the gas transportation system is far preferable to fine-tuning of the curtailment and diversion rules in anticipation of more frequent curtailments.

The Energy Commission agrees that infrastructure improvements are a more prudent approach to meeting the State's growing need for natural gas than increasing reliance on curtailment rules. The Energy Commission also agrees that many complexities would have to be considered in designing an efficiency curtailment rule. Nevertheless, the Energy Commission sees merit to developing an efficiency-based curtailment rule. The Energy Commission will conduct additional analysis to develop an efficiency curtailment scheme, but in this report, makes no firm recommendation on specific changes to the pro-rata curtailment rules currently in place.

In-State Natural Gas Production

The Energy Commission received comments on the potential to increase in-state gas production beyond current levels from CIPA and Calpine. The Energy Commission supports efforts to increase in-state gas production. Although PG&E has stated that they are moving to resolve issues associated with selling off their gathering system, as provided in the Gas Accord, in-state gas producers have stated that they are not making sufficient progress. In addition, producers

¹² An Economic Evaluation Of Alternative Interstate Pipeline Projects To Serve California, Energy Commission, March 1989.

with low Btu natural gas raised a number of barriers to getting their production to the market.

Not all of the problems with in-state natural gas production can be placed on utilities. Some of the gas produced in California does not meet required specifications for pipeline quality gas and some of the gas does not conform to California Air Resources Board requirements for natural gas fueled vehicles. Efforts are underway to solve those problems and the Energy Commission will continue to monitor the situation.

The Energy Commission is aware of several pieces of legislation that would provide incentives and remove barriers to in-state natural gas production. The Energy Commission recommends that an investigation be conducted to identify any remaining barriers or incentives, not addressed in these legislative initiatives, that would increase in-state natural gas production.

CHAPTER 3 – NATURAL GAS SUPPLY

OVERVIEW

This chapter addresses natural gas supply issues.

California produces about 15 percent of its natural gas in the State while the remaining 85 percent of supplies are brought into the State from natural gas resource basins in North America via a system of interstate pipelines.

Since the mid-1980's, in-state production has been declining. To increase available natural gas supplies, California could take steps to increase in-state production.

Drilling activity in North America has also declined. However, with the rise in natural gas prices over the last 12 to 18 months, drilling activity has increased. This increased activity should provide adequate natural gas supplies to meet the needs of California, and the rest of the United States, for the foreseeable future.

NATURAL GAS SUPPLY SOURCES

As shown in **Figure 3-1**, California receives gas supply from five areas. These resource basins include the Western Canadian Sedimentary Basin, the Rocky Mountain Basin, the Anadarko Basin, the Permian Basin, and the San Juan Basin.

The North American natural gas resource base is estimated at 975 trillion cubic feet (Tcf) in the United States (including nearly 160 Tcf of proven reserves) and an additional 417 Tcf in Canada. The United States Geological Service estimates that this resource base, which includes proven reserves ready for production and resources that could be developed and produced economically, should provide affordable natural gas supplies to serve the nation for the next 50 years.¹³

In addition to these natural gas resources, the natural gas industry is continually exploring all options for natural gas development. Potential options to increase gas supply for California range from natural gas from far Northern Canada and Alaska, to liquefied natural gas that would be shipped by tanker to West Coast terminals.

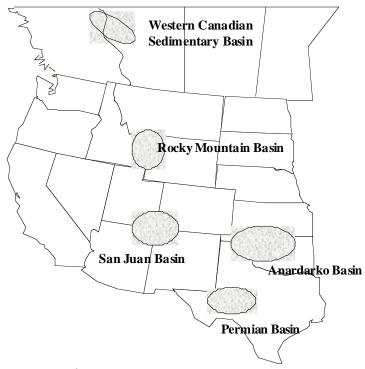
¹³ United States Geological Survey, **1995 Assessment of the United States Oil and Gas Resources** and **An Assessment of the Undiscovered Hydrocarbon Potential of the Nation's Outer Continental Shelf**.

Natural Gas Production Trends

Drilling rigs are deployed in a cyclical pattern. Surpluses of gas supply tend to depress natural gas prices below the cost of production. As a result of low prices, producers reduce exploration and development activities, which decreases the number of operating drilling rigs. Shortages of gas supplies increase prices above the cost of production. This price increase provides economic incentives for producers to boost exploration and development, which increases the number of operating drilling rigs. This cycle continues indefinitely with prices averaging out roughly at the cost of production.

Figure 3-1

Natural Gas Supply Basins to California



Source: California Energy Commission

At the wellhead, the growth in supply has not kept up with growth in demand in North America. Because of the low prices, producer exploration and development budgets were relatively low in North America. High prices have brought us into the midst of a drilling boom.

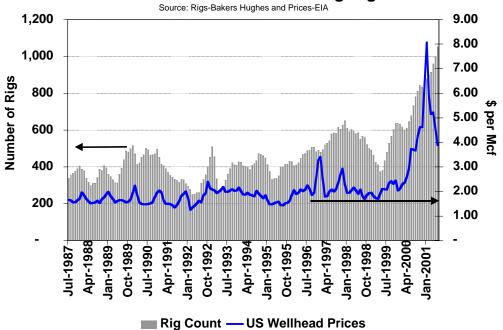
Gas production in the United States in 1998 was 19 Tcf. The National Petroleum Council projects production to increase to 25 Tcf by 2010. Much of the increase

can be attributed to the need to supply increased power generation, both in the United States and Canada.¹⁴

To keep up with production, drilling activity has reached record levels. In September 2000, more than 800 rigs were actively drilling, which is far above the 10-year average of 454 rigs per year. The current total of 971 active drilling rigs support industry opinion of the need to have 600 to 800 rigs actively drilling, to match production capacity with expected growth in demand.¹⁵ To maintain the current level of drilling, anticipated wellhead prices must remain higher than the prices experienced in 1999.

As **Figure 3-2** indicates, in April 1999 the active rig count dropped to 371, as average wellhead prices fell below \$2.00 per MMBtu. Shortly after that point, the average wellhead price in the United States began to climb and drilling activity followed. By September 2000, the active rig count had risen to 813, and more recently, to 971. Once drilling activity begins, natural gas deliveries normally take several months to a year for wellhead supply to be brought to market; thus, with sustained higher rig activity, natural gas wellhead production should be in balance with demand in two to three years.

Figure 3-2
Comparing Monthly U.S. Wellhead Natural Gas
Prices and Active Gas Drilling Rigs



¹⁴ National Petroleum Council, *Meeting the Challenges of the Nation's Growing Gas Demand*, 1999.

¹⁵ Bakers-Hughes, May 2001

California Natural Gas Production

Starting in the mid-1980's, California's in-state natural gas production declined, mostly from non-associated gas or gas that is not produced as a by-product of oil production. In 1985, in-state natural gas production averaged 1,352 MMcfd. However, by 1996, in-state production levels had sunk to about 800 MMcfd. Since reaching its lowest levels in 1996, production has climbed to over 1,000 MMcfd in 2000¹⁶.

California producers hold a locational advantage over gas producers in other regions.¹⁷ In spite of this advantage, in-state gas has lost significant levels of market share during the past 10 to 15 years. The steady decline in market share was largely due to a combination of events, including increased wellhead price competition, contractual hookup restrictions between producers and PG&E (that precluded producers from gaining access to the potential customers), and a falling potential resource base.

The PG&E Gas Accord settlement was intended to relax the hookup restrictions by requiring that PG&E sell its gathering systems. The Accord assumed that an independent natural gas gathering company would have an incentive to provide rapid and efficient service for producers to bring new production to market. PG&E has yet to divest its gathering system, and producers report that PG&E continues to restrict access to the market.

While overall in-state natural gas production has increased since 1996, California's market percentage share of the natural gas market has declined. In 1986, California gas satisfied more than one-quarter of consumer needs. However, by 1997, in-state producers supplied only about 15 percent of the California gas market, a share that continues today.

Figure 3-3 illustrates the trends in California natural gas production. As shown in the graph, non-associated gas production has experienced the greatest decline. However, the Energy Commission estimates that California production has the potential to grow over the next two decades, reaching over 1,200 MMcfd by 2022.

The Elk Hills natural gas field contributed significantly to the recent upturn in total in-state natural gas production. Elk Hills, located in Kern County, remains the largest producer of associated natural gas in California. Originally, Elk Hills was

¹⁶ The California Division of Oil, Gas, and Geothermal Resources reported that, in 2000, natural gas production climbed to about 1,030 MMcfd, up from about 880 MMcfd in 1998.

¹⁷ The cost of natural gas produced in the State does not include the cost of transporting gas from out-of-state locations.

part of the Naval Petroleum Reserve. About half of the natural gas produced by Elk Hills was re-injected into oil producing formations to stimulate crude oil production. When Occidental Petroleum purchased Elk Hills in 1998, it began to sell all the production. This accounts for much of the increase in production statewide.

In addition, other developments in northwest Kern County may provide new resources for California. East Lost Hills, located in this area, may contain 190 Bcf of natural gas¹⁸. Increased production from Elk Hills, Rio Vista, and new areas can increase California's in-state production market share outlook. For example, Tri-Valley recently reported it might have found another 3 Tcf in gas reserves near Delano, California.¹⁹

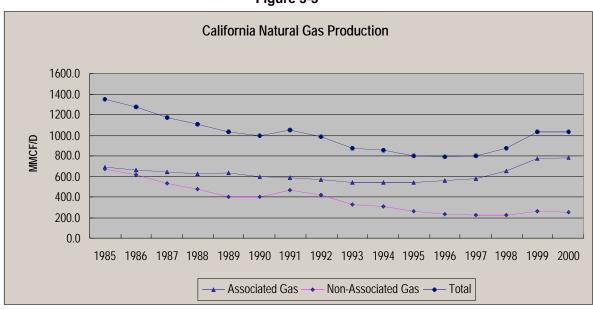


Figure 3-3

Source: Data for graph came from the California Division of Oil, Gas, and Geothermal Resources.

At the end of 1999, estimated proven reserves, onshore and offshore, stood at 3.48 Tcf. These reserves should allow California producers to continue to provide approximately 15 percent of the California market. In-state market share could change if producers expand their drilling activity as a result of higher natural gas prices, and obtain increased access to the market.

INCREASING IN-STATE NATURAL GAS PRODUCTION

The Energy Commission supports efforts to increase the production of in-state natural gas to supplement natural gas supplies. Two issues associated with instate production currently limit the amount produced and used in California.

¹⁸ Berkley Petroleum: Reported in the Bakersfield Californian.

¹⁹ NGI, April 16, 2001.

First, regarding the PG&E Gas Accord, gas producers have raised concerns about being able to get hook-ups to utility gathering and pipeline systems. Second, low-Btu gas produced in-state has difficulty getting to market.

Although PG&E indicates that it is in negotiations to implement portions of the Gas Accord (that call for them to sell-off their gathering system), producers report that progress is not being made. The Energy Commission supports the rapid implementation of the Gas Accord provisions relating to PG&E's gathering system.

Ideally, a company whose sole purpose is to provide gathering services for California production would be the most efficient method for meeting the producer and the utility's needs. Several large and strategic gathering system hookups to the utility system could be made. Subsequent new production would no longer need to be connected with the utility, but with the gathering company's system.

Presumably, the gathering company would quickly move to make new production additions to its system, since its earnings are based on its gathering operations. Additionally, the company would also make adjustments to more efficiently move gas through the gathering system. Overall, an independent gathering company would meet producers' needs by quickly getting its production to market, and the utilities needs by adding incremental new supplies to its system²⁰.

Regarding low Btu natural gas, resources in the northern part of the Sacramento Valley include natural gas with Btu contents lower than what is allowed in the utility pipeline system. Primarily, this is caused by small to large quantities of noncombustible elemental nitrogen and carbon dioxide. There are two options to raise the Btu content: 1) remove the nitrogen, or 2) blend higher Btu gas with low Btu gas. Both processes are currently in use in Northern California. At the Robins field, the nitrogen is being removed cryogenically from the production stream.²¹ This process was also applied to the Chowchilla field located in the San Joaquin Valley. In other areas in Northern California, the low Btu gas is being blended in the utility pipeline system with natural gas having a higher Btu content.

A third marketing option is to deliver the low Btu production directly to a customer who has the facilities to consume the low Btu gas. This could be on-site consumption, or through a dedicated delivery system.

²⁰ Calpine testified in the CEC June 5, 2001 Natural Gas Infrastructure hearing that more efficient handling of its in-state owned production would significantly increase its production.

²¹ Jim Campion, Division of Oil, Gas & Geothermal Operations.

The Energy Commission supports the production and consumption of low Btu gas. At this point in time, rather than regulatory approaches, the Energy Commission believes the prudent approach is leaving it to the market to determine which method of dealing with low-Btu gas is the most beneficial. The Energy Commission should continue to monitor this situation to assure that barriers to low Btu gas production are removed.

The high Btu level of some of the gas looking for a market in the Southern California utility system is causing problems in the SoCal Gas system. The system average Btu level in some areas is above the specification set by the Air Resources Board for natural gas fueled vehicles. The higher Btu content does not affect the other customers on the utility system. Options to solve the problem are under study. These include reducing the Btu content at the well head or at the vehicle refueling station. Another option is to change Air Resources Board's specification, which could lead to a redesign of the vehicle fuel burning system. Approaches are also being investigated to develop an off-the-utility system need for the gas, as distributed generation located at the wellhead or at a central point in a gathering system.

CHAPTER 4 – INTERSTATE PIPELINE CAPACITY AND EXPANSIONS

OVERVIEW

This chapter describes the potential constraints on the interstate pipeline system in meeting California's growing demand for natural gas.

California depends on a system of *interstate* pipelines to deliver natural gas to the State from the different resource basins throughout North America, as outlined in *Chapter 3*. For the most part, natural gas flows from the interstate pipelines into the *intrastate* natural gas pipeline systems of California natural gas utilities for delivery to end-use customers.

INTERSTATE PIPELINE SYSTEM

As previously noted, interstate natural gas pipelines supply about 85 percent of the natural gas consumed in California. At times this past winter, constraints on the El Paso system caused by upstream demand reduced the effective capacity reaching California. This contributed to high prices for natural gas in California in 2000 and early 2001. Without expansion by interstate pipeline companies, upstream demand may pose an ever-increasing threat to the reliable delivery of natural gas to California.

Because California is at the end of the interstate pipelines, California is at a disadvantage in the current market-based natural gas pipeline system.²² With the shift to competition in the United States natural gas market over the last two decades, California must now depend on the market to expand interstate pipeline capacity to meet growing demand. Increases in upstream demand do not automatically translate into expansions of interstate pipeline.

Currently, interstate pipeline companies test market demand for expansions through an open season process. This process involves soliciting market participants' interest in capacity expansions, either through binding or non-binding commitments. But pipeline expansions are not likely to occur without the necessary contractual commitments from natural gas transporters or marketers. If market participants do not anticipate increased demand, they could run short of interstate pipeline capacity.

California, because of its position at the end of the interstate pipeline system, can be faced with paying high prices when upstream demand reduces the flow of

²² California would not be at a disadvantage if gas consumers entered into enough long-term firm contracts and the interstate pipelines honored their commitments to provide sufficient capacity to serve both California and the upstream customers. These contracts could help to mitigate prices and assure long-term supplies.

natural gas reaching the State. Evidence regarding the causes of the high natural gas prices experienced in California last winter has been presented in the previously mentioned FERC proceeding involving El Paso. A witness for El Paso in that proceeding stated:

"I also present information on the other factors that account for the increase in natural gas prices in California relative to the eastern United States. The increase occurred because of large increases in the demand for gas due to increased gas-fired electric generation and insufficient natural gas infrastructure <u>to and within</u> California to meet demand." (emphasis added)²³

This was explained by an Executive Vice President of El Paso Corporation and President of El Paso Corporation's Pipeline Group to mean:

"Likewise, increased deliveries to 'east-of-California' full requirements customers from time to time have an impact on available capacity to California."²⁴

In other words, this past winter the interstate pipeline system operated by El Paso did not have enough capacity to serve both California and the customers between California and the supply basins. The shortfall in capacity was absorbed by California, and not the upstream customers. This is due, in part, to the decision a few years ago by California to turn back part of its rights to firm capacity on the El Paso system. It may also be due to the failure by El Paso to honor its contractual commitment to deliver capacity paid for by California.²⁵

Existing Interstate Pipelines Connected to Supply Basins

Four interstate pipelines connect California to supply basins. The four primary interstate pipelines that deliver gas from remote natural gas production basins into the California gas utilities systems are listed below:

- The PG&E Gas Transmission-Northwest (GTN) pipeline (extends from the Canadian border to the California-Oregon border at Malin);
- The Kern River Gas Transmission Company (Kern River) pipeline (originates in Wyoming and merges with the Mojave pipeline at Daggett, California, to form the Kern/Mojave pipeline);

²³ FERC Docket No. RP00-241-000, Exhibit EPM-1, Prepared Direct Testimony of Dr. John R. Morris, p. 5

²⁴ FERC Docket No. RP00-241-000, Exhibit EPNG-15, Prepared Direct Testimony of John W. Somerholder

²⁵ This issue is before the FERC in several dockets.

- The Transwestern pipeline (extends from West Texas to the California-Arizona border at Needles, California);
- The El Paso Pipeline System (is divided into a Northern and Southern system, delivering gas from the San Juan, Permian, and Anadarko basins into California at Topock and Ehrenberg).

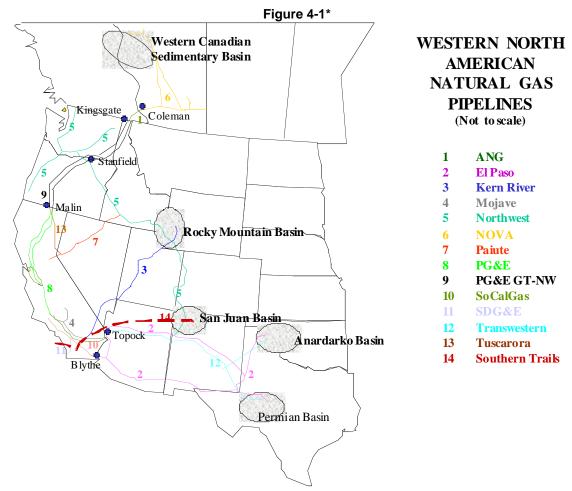
Table 4-1 shows the current capacity of interstate pipelines at the California border. Appendix A provides more detail on how these pipeline systems operate and their current capacities.

Table 4-1

Interstate Pipeline	Delivery Capacity (MMcfd)
PG&E-GTN @ Malin	1,930
Kern River	700
Transwestern @ Needles	1,090
El Paso @ Ehrenberg	1,240
El Paso @ Topock	2,080
Total Delivery Capacity	7,040

Source: California Energy Commission

Figure 4-1 shows the locations of major interstate pipelines. These interstate pipelines can deliver more gas supply to California than the California gas utilities can accept. For example, in 1992 the Transwestern pipeline capacity was expanded to deliver an additional 340 MMcfd to the California border. Of this amount, about 40 MMcfd is used by customers who are located east of the California border. The remaining portion of the expansion was not matched by a corresponding increase in California receiving capacity, leaving about 300 MMcfd "stranded" at the California border.



* Lighter lines on map denote light colors that can be viewed in electronic version. Source: California Gas Report 2000 prepared by the California gas utilities.

During the winter of 2000-01 Transwestern was running full to the California border. PG&E is able to receive up to 1140 MMcfd at the California border from a combination of deliveries from El Paso and Transwestern. The extra 300 MMcfd was delivered to PG&E. Because of the interconnection between PG&E with El Paso and the interconnections between PG&E and Transwestern, the stranded 300 MMcfd capacity was transferred to El Paso.

El Paso had about 500 MMcfd unused capacity on its northern system during the winter months. Besides the 300 MMcfd stranded capacity transferred to it due to market conditions, both PG&E and Mojave were running under capacity. Demand on both pipeline systems was not high enough to fully utilize capacity available on these pipelines. Each pipeline could have taken in the neighborhood of another 100 MMcfd during this period.

As discussed in Chapter 5, steps are being taken to increase receipt capacity in California.

Interstate Pipelines Not Connected To Supply Basins

In addition to interstate pipelines that are connected to supply basins, the Mojave interstate pipeline also receives gas from both the El Paso Northern system and Transwestern pipelines at the California-Arizona border and connects with the Kern River Pipeline at Daggett to form the Kern/Mojave Pipeline.

The Kern/Mojave interstate pipeline is referred to as a "bypass" pipeline. Bypass occurs when an interstate pipeline directly serves a customer without utilizing existing natural gas utility (local distribution company) facilities. In this way, customers can first, avoid paying utility distribution charges, and second, regulation by the CPUC.

Kern River and Mojave were the first interstate pipelines that came within the California border, and thus they were the first interstate pipelines in the State to bypass the intrastate system regulated by the CPUC. Before Kern River and Mojave, all the interstate pipelines ended at the California border and transferred the gas to a California utility pipeline.

The California gas utilities have a monetary incentive to limit interstate pipeline activity in California. They want to avoid bypass since a customer that does not utilize existing local distribution company facilities does not pay for those facilities, nor do they pay for any of the overhead associated with taking service from the local distribution company.

Bypassing the interstate pipeline system has important consequences for pipeline capacity and expansions. For example, a customer that leaves the utility system no longer shares in the cost of operating that system. This can cause the rates for the remaining customers to increase. In contrast, a new customer can directly connect to an interstate pipeline, thus avoiding connection to a gas utility system. Neither of these customers shares in the costs of operating the utility system. Avoiding these costs may explain, in part, the interest in Kern River by electric generation developers.

On the other hand, the new bypass pipelines can promote competition for service with the local distribution system. Because of cross subsidies that occur in the utility's rates, noncore customer rates are often higher than the actual costs to provide service to them. With the threat of an interstate pipeline entering into its system, the utilities have an incentive to review, and possibly change, their rates. This was the case several years ago when Mojave had proposed to extend service into the Sacramento and Bay Areas.

PG&E rates were in the area of a \$1.25 per MMBtu while Mojave was offering under \$.50 per MMBtu. PG&E made some rate adjustments that lowered their rates for noncore customers to be competitive with the Mojave transport price. For this reason and others, the expansion did not occur at that time.

Bypass may also explain the deliberate decision making of gas utilities, such as SoCal Gas, when faced with decisions to invest in capacity expansion to eliminate bottlenecks on its system. As explained in the section on SoCal Gas in *Chapter 5*, a factor in investment decisions by SoCal Gas is their belief that there will be growth in gas demand by electric generators on bypass pipelines. SoCal Gas took this likelihood into account in deciding whether or not to make any investment to eliminate the bottlenecks on its system. As stated earlier, in April 2001, SoCal Gas decided that it was in the best interest of its ratepayers to expand its receipt capacity. The Energy Commission fully endorses this decision and urges the CPUC to grant appropriate rate treatment for recovery of these investments.

Upstream Demand on Interstate Pipeline Capacity

Natural gas marketers, natural gas utilities, and a handful of end users contract for an interstate pipeline company's delivery capacity on a long-term basis. Marketers bundle their capacity and supply for sale to whomever along the pipeline will use their services. Clients would include a cross-section of the natural gas industry. Service agreements are normally for a one to two year period. Shorter periods, such as monthly or seasonally, may also be negotiated.

The growth in upstream demand on the interstate pipelines will reduce the flow of gas to California unless additional interstate pipeline capacity is built. Upstream users can bid away or displace California users because California noncore gas users have historically relied, for the most part, on short-term (one to two years) contracts with marketers. When these contracts expire, upstream customers have the opportunity to bid on these contracts for their own use, displacing California customers. Additionally, the short-term contracts may have been either interruptible or recallable capacity from secondary markets, not firm uninterruptible capacity.

When upstream users are signing firm, long-term contracts for transportation services, these contracts divert the natural gas that would flow into California to other users. In response, California noncore gas users (through their suppliers) have and will bid on new capacity expansion to secure firm long-term capacity. The Energy Commission will continue to monitor the market for transportation services to determine whether California will continue to receive sufficient supplies of natural gas.

Additional upstream demand that could further reduce flows to California is the demand that would result with the construction of some portion of the 31,000 MW of proposed electric generation in the Southwest (See **Table 2-1**). One recent example is the case of two merchant plants under construction in Arizona, the 2,210 MW Redhawk facility and the 1,000 MW Arlington Valley generating plan.²⁶

²⁶ The CPUC, SCE PG&E and SoCal Gas along with others have filed a complaint at FERC requesting mandatory expansion of the El Paso system . The complaint was triggered, in

INTERSTATE PIPELINE EXPANSIONS

As previously discussed, increases in upstream demand for natural gas will decrease the flow of natural gas into California, unless new pipeline capacity is added. Market participants are recognizing the need for new capacity, as illustrated by recent open seasons to solicit interest in expansion of interstate pipelines. The market is displaying a keen interest, with offered capacity being significantly oversubscribed. The details of the expansions are presented in **Appendix A**.

Any new pipeline capacity would be added to meet not only California's needs but also the needs of neighboring states. Therefore, exactly how much of the proposed incremental interstate capacity additions will reach California depends on who contracts for the new capacity and what demand they intend to serve. Those bids for open season pipeline capacity may apply to all or part of the new power plants in Oregon, Washington, Nevada, and Arizona. New out-of-state gas-fired power plants may displace California gas-fired plants or may create the need for peaking capacity as opposed to base load capacity in California.

California must rely on electric generators to obtain the necessary pipeline capacity to serve their units so that the State can rely on in-state gas-fired generation. California's electricity system is part of an integrated western grid, which over time has provided significant opportunities to take advantage of economies of seasonal diversity, and other variations between states throughout the West. Likewise, California is part of a regional natural gas market. This market determines the timing and extent of pipeline expansions, and it indirectly impacts the location of gas-fired power plants with assured supplies of natural gas throughout the West.

Proponents of the proposed interstate pipelines in all likelihood have estimates of the following:

- the probable future transportation premiums due to the aging of coal and nuclear units in the West,
- the population and economic growth upstream from California,
- the likelihood of summer heat storms,
- the potential freezing at gas wellheads in Canada and the Rocky Mountains, and
- other such events.

California needs to continuously monitor the expansion plans of interstate pipelines and assess the regional conditions listed above to determine whether California gas utilities, marketers, and electric generators are securing sufficient supplies to meet California's needs for natural gas.

part, by the announcement by El Paso that it intends to supply 620 MMcfd of natural gas to these two new plants in Arizona.

CHAPTER 5 – INTRASTATE PIPELINE SYSTEM

OVERVIEW

This chapter addresses the existing intrastate pipeline system and the need for system expansions.

Interstate pipeline systems bring natural gas supplies to the California border for delivery to the State's three natural gas utilities: PG&E, SoCal Gas and SDG&E. The receipt capacity for the gas utilities is shown in **Table 5-1**. These utilities have intrastate pipeline systems that deliver gas throughout their service areas to end-use customers.

The configuration and operations of these intrastate pipeline systems vary depending on the physical characteristics of loads and interstate pipelines, as well as the weather conditions that the natural gas system is designed to accommodate. The backbone system of the utilities consists of the gas pipelines used for transmission, not distribution.

Table 5-1

	Table 3-1		
California Receipt Capacity	MMcfd		
PG&E			
Redwood- Malin	1,905		
Baja Path	1,140		
Kern River/Mojave (300)			
Needles (400)			
Topock (1,140)			
SoCal Gas			
Needles	750		
Hector Road	50		
Topock	540		
Ehrenberg	1,210		
Mojave	400		
Needles (300)			
Topock (400)			
Kern River	700		
Total	6,695		
Winter Receipts at Malin drop to 1,500 to 1,750 MMcfd due to increased			
l			

Winter Receipts at Malin drop to 1,500 to 1,750 MMcfd due to increased demand in PNW Region.

In addition to transmission listed, there is approximately 1,000 MMcfd in California production.

Source: California Energy Commission

The gas utilities have the responsibility to supply the needs of the core customers (the residential and small commercial and industrial customers) whose demand for natural gas increases in the winter, as space heating needs increase. The gas utilities also have the responsibility to assure that the backbone system can accommodate the needs of all customers, both core and noncore. The actual

acquisition and billing arrangements for the noncore customers are provided by the over 50 marketers serving California. The arrangements for core customers remain the responsibility of the utility.

PG&E and SoCal Gas use a slack capacity standard to determine when to expand their backbone pipeline capacity. The CPUC defined slack capacity in its Decision 97-08-055 as: "Slack capacity is capacity in excess of demand needed to generate the benefits of competition". When demand equals capacity, there is no slack capacity. When there is no slack capacity, customers lose the benefits of competition, and prices increase overall or spike upward.

PG&E and SoCal Gas also determine whether they can recover their costs in rates from backbone expansions before making such investments. A regulatory approach that encourages such investment (to assure slack capacity) can mitigate or prevent the price spikes experienced this past year in California.

PG&E - CALIFORNIA GAS TRANSMISSION SYSTEM

The PG&E Backbone Gas Transmission System runs from Malin, Oregon to Topock at the Arizona border. The 1140 MMcfd Line 300 originates at Topock and terminates in the San Francisco Bay area at Milpitas. The 1,905 MMcfd Line 400/401 originates at Malin on the Oregon border, with Line 400 terminating at Antioch and Line 401 terminating at Panoche.²⁷ The third source of gas for PG&E is 200 MMcfd from in-state production.

At Malin, the PG&E Gas Transmission-Northwest (GTN) interstate pipeline from Canada and the PG&E Line 400/401 receipt pipeline are roughly matched. On the other hand, the capacity of the interstate pipelines delivering natural gas from the Southwest exceeds the receipt capability of PG&E's Line 300. PG&E has the option to take 300 MMcfd from Kern/Mojave at Daggett, 1,140 MMcfd from El Paso at Topock, and 400 MMcfd from Transwestern at Topock. The PG&E Line 300 receipt pipeline has a total capacity of 1,140 MMcfd, which is 700 MMcfd short of what PG&E could take if their system was expanded.

Not all of the PG&E pipeline capacity serves PG&E customers. PG&E has also agreed to allocate pipeline capacity to natural gas marketers for off-system deliveries. Recently, PG&E has been shipping from 300 to 400 MMcfd on Line 300 from Topock and Daggett via Wheeler Ridge and then onto the SoCal Gas system. This gas is consumed by a cross-section of the SoCal Gas customers, including core and noncore customers.

Various parties, including municipal utilities, customers and marketers, use the remaining capacity on the PG&E backbone pipelines after the core and

²⁷ The total capacity of Line 400/401 is 1,905 MMcfd, with 1,803 MMcfd rated as firm capacity and the remainder rated as available

off-system transportation capacities are subtracted from the PG&E backbone capacity. This capacity is available for these customers and marketers to use under a CPUC approved tariff to ship natural gas.

In the year 2000, PG&E had little slack capacity. When testifying at the January 25, 2001 Energy Commission hearings on siting constraints, PG&E testified about: "... the need to have slack capacity available to basically tone down the prices that we have seen from the commodity side of the market." (Transcript p. 48) PG&E further explained: "...as you run the system tighter and tighter you're not leaving room to use storage or flowing capacity for arbitrage because essentially your system is full or very close to being full every day." (Transcript p. 54)

PG&E winter demand for the past few years is compared with the 2000-2001 winter demand in **Figure 5-1**. The figure has three components: monthly demand spanning November through March for 2000-01 and for the five winters from 1995-96 through 1999-00, and the peak day demand for each of the winters.

Several observations may be made from the figure. First, the 2000-2001 winter monthly average day demand was 400 MMcfd or more than the past five year average. Even with the much higher demand this past winter, on an average daily basis the demand did not exceed PG&E's 3,200 MMcfd in firm receiving capacity. In December 2000 pipeline capacity utilization was 74 percent, in January it was 90 percent, and in February and March it was 95 percent.²⁸ PG&E had some slack receiving capacity available which helped to mitigate high prices.

²⁸ This is based on data PG&E routinely files with the Energy Commission.

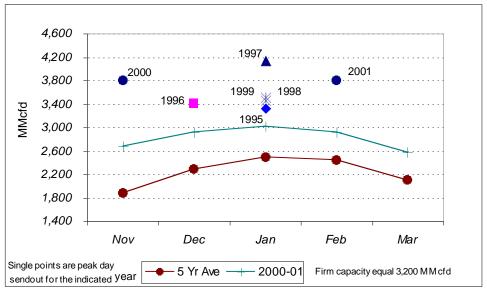


Figure 5-1
PG&E Total Winter Natural Gas Demand

Source: California Energy Commission

Interestingly, the peak day demand for 2000 and 2001 occurred in the winter of 2000-2001. Both November 2000 and January 2001 experienced peak day demand in the area of 3,800 MMcfd. But in each instance, demand on a monthly average basis fell back to levels that were lower than PG&E's firm capacity. This is substantially different from what occurred on the SoCal Gas system for the winter of 2000-2001. As discussed in a later section, SoCal Gas average daily demand was considerably higher than the utility's firm receiving capacity for several months.

The demand for electricity generation was primarily responsible for driving up the demand in the PG&E system. As **Figure 5-2** indicates power plant demand for the winter 2000-2001 was two to two-and-a-half times higher than the past five-year monthly averages. While these are more like summer demand levels, they were up to 400 MMcfd lower than power plant demand in the SoCal Gas system.

PG&E customers did pay high prices for their gas supplies last winter, but as dicussed in **Chapter 7**, border prices were lower for PG&E than for SoCal Gas. While PG&E demand did reach high daily peaks, overall demand remained below firm receiving capacity. PG&E had some slack capacity on its system, giving the shippers a little manuevering room to provide for limited supplier competition.

Figure 5-2
PG&E Winter Electric Generation Natural Gas Demand

Source: California Energy Commission

PG&E held an open season to consider the allocation of its existing backbone pipeline system. In addition, 200 MMcfd of new capacity on its Redwood system was also to be considered by the parties in their bids.²⁹ These are binding bids that would become effective on January 1, 2003.

PG&E subsequently suspended its open season and requested to withdraw its application from the CPUC for approval of its open season procedures. The CPUC granted the request and ordered PG&E to move forward with the Gas Accord II by filing it by October 6, 2001.³⁰ In that decision CPUC granted the motion for PG&E to withdraw its request for open season procedure approval. PG&E was directed to not file for an open season until it files an application for proposing a market structure and rules for periods beginning Jan 1, 2003.

SOCAL GAS SYSTEM

The SoCal Gas system has 3,500 MMcfd of firm receipt capacity. In addition, SoCal Gas has access to 200 MMcfd of interruptible capacity. This added capacity, primarily at Ehrenberg and Wheeler Ridge, is available on cold days with high supplier pressure and high local demands.

The SoCal Gas storage fields are capable of storing a total of 105.6 Bcf of natural gas. The withdrawal rate for SoCal Gas is 3,200 MMcfd, of which 1,900

²⁹ PG&E has indicated that the Redwood expansion has an incremental cost of about 10 cents per MMBtu.

³⁰ Decision 01-09-006 issued on September 6, 2001

MMcfd is reserved for core customers. Together, storage and backbone can theoretically meet a 6,000 MMcfd peak demand day in January. The historical peak on the SoCal Gas system is 5,300 MMcfd.

SoCal Gas designs its backbone system to maintain 15 to 20 percent slack capacity over projected demands, assuming normal weather conditions. This policy is consistent with the CPUC interstate pipeline interconnection policy as expressed in Decision 90-02-015. As explained above, slack capacity is needed for operational flexibility and to foster competition among gas suppliers.³¹

SoCal Gas could receive an additional 200 MMcfd from El Paso at Blythe. In the early 1990s SoCal Gas expanded its southern system to accommodate an additional 200 MMcfd in deliveries from El Paso at Blythe. El Paso never made the necessary pipeline upgrades to match the SoCal Gas expansion. Because of this, SoCal Gas cannot firmly rely on the use of the expanded pipeline capacity, consequently the 200 MMcfd is now treated as non firm.

SoCal Gas winter demand for the past few years is compared with the 2000-01 winter demand in **Figure 5-3**. The figure has three components: monthly demand spanning November through March for 2000-01 and for the five winters from 1995-96 through 1999-00, and the peak day demand for each of the winters. SoCal Gas has 3,500 MMcfd in firm receiving capacity. This includes deliveries to SDG&E.

³¹ SoCal Gas testified at the January 25, 2001 Energy Commission hearing on siting constraints regarding slack capacity: "...we would not want to be operating with no less than 10 percent excess or slack capacity on a long-term basis, and we're going to continually look at that situation and we may decide to build more excess backbone capacity as a means of encouraging gas-on-gas competition in Southern California." (transcript p. 65)

5,500 2001 5,000 1998 4,500 1999 MMcfd 1995 4,000 1997 1996 3,500 3,000 2.500 2,000 Nov Jan Feb Mar Dec Single points are peak day 5 Yr Ave 2000-01 sendout for the indicated year-Firm capacity is 3,500 MM cfd

Figure 5-3
SoCal Gas Total Winter Natural Gas Demand

Source: California Energy Commission

Several insights may be drawn from **Figure 5-3**. The most startling is that the overall natural gas demand in Southern California by far exceeded anything that has occurred during the recent past. Prior to this past winter, firm pipeline capacity was capable of meeting the average-day demand for each month. While past year's peak-day demand spiked above firm capacity it always fell to levels below the firm capacity. Storage would have been relied on to meet the demand for the days associated with the higher demand levels.

During this winter average day demand surpassed most of the past years peak-day demand and was considerably higher than SoCal Gas' firm receiving capacity. This caused both the storage facilities and the pipeline system to operate at very high utilization levels for much of the winter. SoCal Gas receiving capacity operated at 101 percent in December 2000 and at 103 percent in January through March 2000.³³ In **Figure 5-3** the area between the firm capacity of 3500 MMcfd and the total demand line for 2000-01 represents the level of demand that was placed on the storage facilities. As can be seen, large quantities of gas were withdrawn from storage in January and February 2001.

SoCal Gas could not get more gas into their system from interstate pipelines. As a consequence, there was no way that Southern California could have utilized the 500 MMcfd per day of the unused El Paso capacity to meet its needs. All of

³² In Figure 5-1, total demand is the demand that was satisfied from both flowing pipeline supply and from storage withdrawals.

³³ This is based on data SoCal Gas routinely files with the Energy Commission.

SoCal Gas firm and any nonfirm capacity available to it was being used at the time.³⁴

As indicated earlier, there was some spare capacity on the El Paso system that could have been used by the SoCal Gas system if El Paso had expanded its system at Blythe to match the expanded receipt capacity on the SoCal Gas system. In hindsight, that would have relieved some of the pressure on the storage system and could have helped to moderate prices some. Alternatively, if SoCal Gas had originally built up its backbone line from Topock rather than its line from Blythe, it would have had access to some of the unused 500 MMcfd in El Paso delivery capacity.

The demand for natural gas in the SoCal Gas system was largely driven by very high demand for natural gas by electric generators. As **Figure 5-4** indicates, the demand for natural gas by gas-fired generators ranged from twice to nearly three times the normal winter electric generation gas demand. This level of natural gas demand for electric generation was more consistent with summer averages

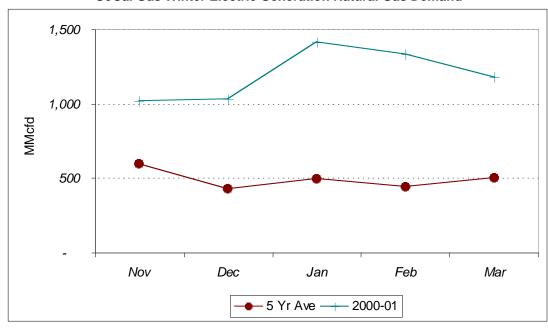


Figure 5-4
SoCal Gas Winter Electric Generation Natural Gas Demand

Source: California Energy Commission

Merchant power plants in California had no economic alternative to burning natural gas. Due to past economics and air emission regulation they only have

³⁴ At certain times last winter, SoCal Gas was taking close to its total receipt capacity. That is it was taking 1,750 MMcfd from El Paso and 750 MMcfd from Transwestern and over 680 MMcfd from various sources at Wheeler Ridge. At the same time, El Paso had up to 500 MMcfd of unused capacity at the California border.

the capability of burning natural gas. The few that do have alternative fuel capability can not fuel switch for economic reasons, but only when natural gas service is curtailed. Therefore, in order for the electricity demand to be met and avoid blackouts, the generators needed gas. Since they were able to pass those costs through in accordance with the market structure rules in existence at that time, they were willing to pay high prices. Under conditions where demand is high and supply is tight and there is a demand that must be satisfied regardless of price, the price will tend to go up.

SoCal Gas operated its system last winter under very difficult circumstances without disrupting deliveries to it customers. The high demand experienced on the SoCal Gas system, which was driven by high power plant needs, and the tight receiving capacity played a major role in setting the stage for high border prices last winter. Demand far exceeded pipeline capacity. During the winter months of 2000-2001, when gas demand was very high, prices were in excess of \$10 per MMBtu. It was not until early March 2001, when demand started to decline, that prices also began to fall.

One concern that SoCal Gas has regarding expanding its backbone system is the regulatory treatment given its last such expansion. In about 1993, the CPUC put SoCal Gas at risk for recovering its investment in the Wheeler Ridge expansion. If volumes of gas flowing across the SoCal Gas system had not justified the Wheeler Ridge expansion, then SoCal Gas would not have fully recovered its investment.

Despite this concern, SoCal Gas is expanding its backbone system. SoCal Gas believes that the natural gas demand in its territory will decrease in the future due to: 1) a return to average hydro conditions, 2) imports of electricity from out-of-state, and 3) increased pipeline bypass. Nevertheless, many market participants have expressed interest in expanded backbone capacity for the SoCal Gas system.

By this coming winter, 375 MMcfd of new receiving capacity will be installed and 24 Bcf of gas already in storage will become useable. The projects proposed by SoCal Gas would increase firm receiving capacity by adding permanent compression at three sites. Capacity would increase 85 MMcfd at Wheeler Ridge, 50 MMcfd at Needles, and 40 MMcfd from lower San Joaquin producers. In addition, SoCal Gas is constructing a 32-mile pipeline link to the Kern-Mojave pipeline system that will allow it to deliver an additional 200 MMcfd into its system.

SoCal Gas has elected to move ahead with these projects and will seek rate recovery in its next biennial cost allocation proceeding (BCAP). The Energy Commission supports the construction of this expanded receipt capacity and urges the CPUC to grant appropriate rate treatment for recovery of these investments.

SAN DIEGO GAS AND ELECTRIC SYSTEM

SDG&E has no direct connection with any of the interstate pipelines. Instead, the SDG&E system receives its gas from its connection with SoCal Gas. Besides serving customers in its traditional service territory, SDG&E also delivers gas to Mexico for electric generation facilities at Rosarito Beach. Currently, SDG&E has a long-term contract (for deliveries to the California border) with El Paso for 10 MMcfd of firm transportation capacity and for 52.5 MMcfd with GTN to serve core customers. SoCal Gas, on behalf of the SDG&E, receives their supplies and transports the natural gas to the SDG&E system.

SDG&E has no storage capability inside its territory, although it does utilize the SoCal Gas storage. SDG&E is totally dependent on flow from SoCal Gas to serve the demands of its customers. The connection between the SDG&E system and the SoCal Gas system is rated at 575 MMcfd in summer and 595 MMcfd in the winter. This past winter, the demand on the SDG&E system exceeded that amount on 11 separate days. This required curtailing SDG&E's noncore customers including electric generators.

The recent stress on the SDG&E natural gas system is due both to high electric generator gas demand at Encina and South Bay and a recent pipeline extension into Mexico to provide gas to a generator at Rosarito. At present, the Rosarito facility draws from 30 to 70 MMcfd with a maximum of about 90 MMcfd. The maximum amount is projected to increase to 182 MMcfd when Rosarito III, with a capacity of 550 MW, becomes operational in 2002.

To alleviate the constraint on deliveries to SDG&E, SoCal Gas increased Line 6900 capacity to provide an additional 70 MMcfd of capacity to SDG&E. In addition, SDG&E could make internal adjustments to its delivery system that would increase its delivery capacity by an additional 130 MMcfd. These adjustments could be operational by the summer of 2005.

The 130 MMcfd may not be needed if the North Baja Pipeline is constructed. For example, Otay Mesa has announced that it has applied to the FERC for approval to construct a 110 MMcfd pipeline from its proposed electric generating facility in San Diego to the North Baja pipeline in Mexico.

As discussed in **Appendix A**, the North Baja pipeline is proposed to bring gas from the El Paso delivery point at Ehrenberg, through Mexico, to the Rosarito Beach power generation facility located in Mexico. Supply from the pipeline could easily flow across the border to SDG&E. These flows would be through existing pipeline that is now delivering natural gas from SDG&E to Mexico for use at Rosarito Beach. Once completed, the North Baja pipeline will potentially relieve the natural gas capacity bottleneck for SDG&E.

The North Baja Pipeline will also relieve SDG&E from the responsibility of delivering gas to Mexico. However, without pipeline capacity additions on the El

Paso system it may divert enough gas from SoCal Gas to cause gas shortages in Southern California. Further analysis will be necessary to estimate the impact of these issues. This may be a critical issue since, as already explained, the inadequate El Paso infrastructure has been identified as a factor in the extraordinarily high gas prices in California this past winter.

LOW HYDRO YEAR OBSERVATIONS

The drought-induced increase in electric generator demand for natural gas, followed by an unusually cold November 2000, eliminated the slack capacity on the gas pipelines serving California in late 2000 and early 2001. The result has been billions of dollars in increased costs of gas to consumers in California. This situation has raised several questions for California.

First, this extraordinary expense brings into question the design criteria used by SoCal Gas and PG&E to assure the availability of slack capacity. Second, If the utilities design their systems to have slack capacity available in an average year, it raises questions about the risks California gas consumers are undertaking when weather conditions are greatly different than average. Third, the Western United States are increasing their reliance on natural gas. This reliance on natural gas raises questions: 1) how often will there be average hydro conditions, average summer and winter temperatures, average output from coal and nuclear electric plants, and average economic and population growth in the United States; and 2) what impact will this have on regional natural gas demand?

SoCal Gas and PG&E's current design criteria were adopted when there was fuel switching capability and much less upstream demand. There is now sufficient justification to support a risk analysis of the California natural gas backbone infrastructure to determine under what circumstances slack capacity is warranted. It appears that all stakeholders and regulatory bodies support SoCal Gas investing to de-bottleneck its system. These expenditures are justified considering that the lack of slack capacity cost billions of dollars. Perhaps, more such investment is needed to meet future demand.

Slack capacity is needed to meet two needs. First, it is needed in conjunction with storage to insure sufficient pipeline capacity to meet California natural gas customers' peak day-month-year demand. Second, from the year 2000 California experience (when demand was high and capacity was short), lack of competition caused commodity prices to exceed what would be considered normal levels for the circumstances. Having slack capacity last year would have more than been paid for through reduced commodity prices.

Promoting higher levels of slack capacity will require a new standard of reliability for the natural gas companies. This reliability standard should include adequate capacity to receive natural gas from storage. The Energy Commission proposes to assess what design criteria should determine slack capacity needs in a world of ever increasing reliance on natural gas.

CHAPTER 6 – NATURAL GAS STORAGE

OVERVIEW

This chapter addresses the natural gas storage issues and the potential impacts of increased electric generator demand on meeting storage targets.

Natural gas utilities typically rely on natural gas from storage to augment supplies flowing through the pipeline system to meet total natural gas demand throughout the year. A natural gas system designed to meet the peak demands that does not include storage would be significantly more costly than the current system. This happens because at many times of the year there would be substantial amounts of unused pipeline capacity. This unused capacity would not generate sufficient revenues to cover investments in pipelines and related facilities.

Consequently, California's existing natural gas pipeline system is designed to meet peak demands by drawing on additional natural gas supplies from storage facilities. Without storage, the gas utilities would literally be unable to meet demand on the peak winter day. Storage is essential to meeting natural gas demand in California.

Another use of storage is to hedge natural gas prices. Basically, one buys and stores natural gas when the price is low, and uses this lower priced gas from storage when the natural gas prices are high. However, this hedging strategy has a down side, as some learned last year in California. Cash prices were higher in the summer than what the futures market indicated for the winter. As a result, many gas users took advantage of this and withdrew their gas from storage. Later in the year, the price for natural gas had increased and the availability of pipeline capacity was strapped. The result was that going into the heating season, storage levels were lower than desirable, and higher priced natural gas had to be purchased to make up for stored gas that had been used.

Each of the natural gas storage operators uses different rules in operating their systems. In general, natural gas storage is broken into three categories: inventory, injection, and withdrawal capacities. Core customers are allocated a certain level of these storage services. A small portion of these services is assigned to the natural gas utility for pipeline balancing activities. The remainder is available for others, such as noncore industrial and electric generators, to place under contract for a one to two year period.

Natural gas storage operators currently indicate that their inventory capacity has been fully subscribed. However, injection and withdrawal rights are still available. Contracting for storage services may be done on a firm or interruptible basis. Should the need for natural gas curtailment occur, interruptible storage

service is subject to a very low priority level. Except for the rare event of a threat to core service, firm storage commitments could be used to meet the noncore customer requirements during a curtailment episode.

In the summer of 2000, increased electric generator demand for natural gas placed increased strain on the natural gas system in California. Natural gas from both PG&E and SoCal Gas storage facilities was drawn on to meet the high gas use by electric generation. In addition, California experienced extremely cold weather in November 2000 that placed additional demands on gas in storage. As a result, both PG&E and SoCal Gas drew heavily on their storage resources during this past winter.

Earlier this year, there was a concern about whether there would be sufficient gas storage in California to serve the needs of the core customers and the year-round needs of electric generators. A further analysis of this situation is discussed in *Appendix D*.

STORAGE FACILITIES

Figure 6-1 shows the location of the underground storage facilities in California. The figure also shows the storage capacity, maximum injection, and withdrawal rates for PG&E, SoCal Gas, Wild Goose, and Lodi Gas. (Wild Goose and Lodi Gas are privately owned storage facilities.) The storage facilities are depleted oil and gas fields that have been modified to allow both injection and withdrawal of natural gas.

Figure 6-1 Max Injection Max Withdrawal Storage Facility Storage (Bcf) (MMcfd) (MMcfd) Pleasant Creek Wild Goose PG&E 98 375 1534 SoCalGas 105 800 3200 McDonald Island SLodi Gas Storage Wild Goose 14 80 200 Medai 12 400 500 Lodi Gas* *Not operational yet. Honor Rancho Goleta Aliso Canyo Playa Del Map not to scale Source: California Energy Commission

As shown on **Table 6-1**, PG&E has the ability to store about 98 Bcf of natural gas. However, while PG&E has 98 Bcf in working storage, it is only able to cycle (use and replace on an annual basis) about 45 Bcf. Of this amount, about 33 Bcf is reserved for core customers. SoCal Gas can currently store about 105 Bcf of natural gas, of which 70 Bcf is reserved for core customers.

Table 6-1 Natural Gas Storage Information						
Storage Facilities	Cap	al Cycle pacity Bcf	Injection Capacity MMcfd		Withdrawal Capacity MMcfd	
	Core	Total	Core	Total	Core	Total
PG&E	33	98*	200	250	1,006	1,534
SoCal Gas	70	105	327	800	1,985	3,200
Wild Goose		14		80		200
Lodi Gas		12		400		500

Wild Goose and Lodi Gas Field are unregulated natural gas storage fields. Lodi Gas Field is expected to be operational by December 2002.

Source: California Energy Commission

In addition to utility storage facilities, there are two relatively new independent storage facilities that are considerably smaller than the utility storage facilities. The Wild Goose facility is now operational. Noncore natural gas customers, such as industrial and electric generators, could use these facilities to store gas for use during their peak periods.

PROPOSED EXPANSIONS

SoCal Gas intends to modify its Aliso Canyon and La Goleta storage fields to add 14 Bcf in storage for the winter of 2001-2002. The modifications would shift gas currently used to maintain pressure to gas available for withdrawal. This will have no impact on SoCal Gas's total storage ability. Withdrawal capacity will be maintained by drilling additional withdrawal wells into each of the two storage fields.

SoCal Gas will also have available this winter 10 to 12 Bcf of the available 24 Bcf total Montebello storage due to the abandonment of the Montebello storage facility as the gas is withdrawn. However, once withdrawn, this storage facility will be closed and no longer available for storage.

PG&E is currently considering expanding the withdrawal rate from McDonald Island storage facility by 400-600 MMcfd. The expansion would depend on the installation of a new pipeline from the storage field to the PG&E system.

A private entity is developing the Lodi Gas storage facility in Lodi, California, in the PG&E service territory. If permitted and constructed, this facility would add

^{*} PG&E is able to annually cycle about 45 Bcf.

12 Bcf in storage capacity to Northern California. Calpine has announced that they have a 10 year contract with Lodi for the use of its facilities.

The Wild Goose storage facility operator has announced its intention to expand from 14 to 29 Bcf by spring 2003. As the result of an open season, Wild Goose has filed an application with the CPUC to expand its injection, withdrawal and working storage capacity as shown in **Table 6-2**. The new storage operation is proposed for use by all natural gas sectors.

Table 6-2 Wild Goose Expansion Plans				
	Current	New		
Injection	80 MMcfd	450 MMcfd		
Withdrawal	200 MMcfd	700 MMcfd		
Working Storage	14 Bcf	29 Bcf		

Source: California Energy Commission

STORAGE OPERATIONS

Historically, natural gas injection into underground storage facilities begins in the spring and continues though the fall months when gas demand is the lowest. Besides injection capacity, the limit to placing gas into storage is based on the availability of unused pipeline capacity. Unused pipeline capacity is generally available after winter demand has dropped to lower levels. This unused pipeline capacity is usually available in the spring and fall, and on low demand days in the summer.

This past year was a good example of the need to have natural gas in storage. From the first of November 2000 until February 2001, PG&E and SoCal Gas withdrew over 90 Bcf of gas from storage. Without the gas in storage, an average of 775 MMcfd of noncore customer gas use would have been curtailed. If only electric generators had been curtailed, that is equivalent to about 3,000 MW. In an actual curtailment, a mixture of industrial customers and electric generation would have been curtailed due to lack of fuel.

YEAR 2001 NATURAL GAS STORAGE NEEDS

Earlier in the year there was considerable concern about the ability of the natural gas storage operators to be able to inject sufficient gas into storage to meet both peak summer 2001 electric generation demand and 2001-2002 winter core heating needs. Entering this past winter, PG&E storage was in satisfactory shape. SoCal Gas November 1, 2000 storage levels were considerably lower than the past five year November 1st average. This was due to a combination of high summer electric generation demand for natural gas, the need to draw heavily on storage after the El Paso pipeline explosion, and the reluctance of large customers to place natural gas into storage to meet winter needs.

Coming out of the winter of 2000-2001 storage levels were low, which is not a surprising condition at the end of winter. During December 2000 through March 2001, SoCal Gas intrastate pipeline receiving points were operating from 101 to 103 percent of firm capacity to meet demand. In addition, SoCal Gas was withdrawing natural gas from storage. The concern at that time was that this level of demand could continue into the spring injection period.

PG&E's backbone system generally operated below capacity during the winter of 2000-2001.³⁵ Because of credit worthiness concerns, which affected their purchasing of flowing gas supply, PG&E appeared to rely more on its gas in storage than what would have been normally expected.

At that time, California, as well as the western states, faced a bleak year ahead. Another dry winter was being experienced, meaning that little hydroelectric generation would be available for the coming summer. This reduction in hydro availability would place more reliance on natural gas fired generation. In early spring, gas fired power plants were operating at levels that were equivalent to what would be expected during the summer months.

It was anticipated that the high levels of gas demand for electric generator would continue into the spring and early summer months. These are the traditional months for filling gas storage. It was feared that high electric generation demand for gas would not leave any pipeline capacity to flow natural gas supplies to the storage fields for injection.

As the injection season began it was generally agreed that PG&E had enough pipeline capacity to meet its storage needs for the coming year. Its problem would be purchasing the supply to put into storage. The real concern was with SoCal Gas. Given the tightness of the receipts of gas in comparison to the high demand the company experienced during the winter, there was real concern about whether SoCal Gas would be able to meet the coming summer and winter storage needs.

As the year progressed, storage operations in both utility service areas took advantage of any unused pipeline capacity for moving gas into storage. Injection facilities operated at or near full capacity, placing gas in storage for core and noncore sectors to meet the coming peak demand periods. **Figure 6-2** shows the current natural gas inventory levels in California. The storage facilities are in excellent condition to meet the coming winter gas demand. While **Figure 6-2** indicates that storage is above the level needed to meet core cold year needs, some of the storage is dedicated for noncore use. Core storage is not quite full

³⁵ Included in PG&E's receipts was 200 to 300 MMcfd for redelivery to SoCal Gas.

yet, but there will be adequate opportunities for the gas utilities to add more to the core inventory.³⁶

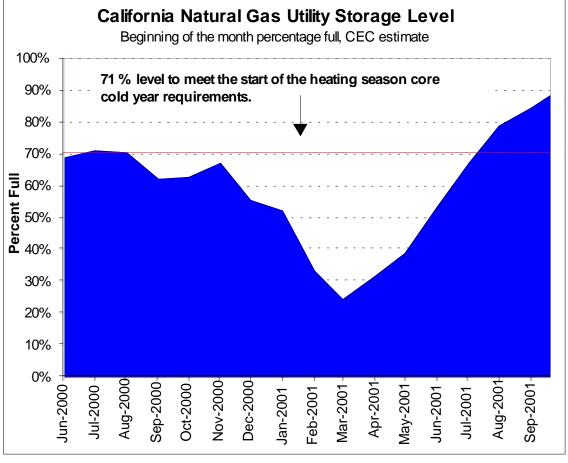


Figure 6-2

Source: California Energy Commission

OTHER STORAGE OPPORTUNITIES

Utilities can store natural gas within their pipeline systems. There are minimum and maximum allowable operational pressures for pipelines. Between these pressures, the system operator may "pack" natural gas into the pipeline until the maximum operational pressure is reached. To meet peak demand, the system may be "drafted" to provide nearly instantaneous supply from the gas "packed" into the pipelines to augment the current flowing supply. As an example, PG&E packs its Southern system during the night and drafts it in the morning to meet its peak early morning demand.

³⁶ In earlier versions of this report scenarios were presented to indicate the potential storage inventories for base case and high gas demand conditions. As the storage level concerns have eased, this work is presented in Appendix D.

Shippers of gas into the utility system are expected to match their supply with the demand they intend to serve. Supply and demand imbalances, from what a shipper nominates and what they actually deliver, often may impact the pack and draft inventory. Tolerances, or imbalance rules, are provided by the utilities to allow for variations in the demand and flowing supply. The CPUC should consider tightening the utility balancing rules on the SoCal Gas system as they have for PG&E. Shippers take advantage of the current rules by running out of balance for much of the balancing period. In these instances, shippers are using the utility system to store gas for them without paying for the storage services they are receiving. This leads to inefficient use of the utility storage and can lead to operational problems for the utility system.

NATURAL GAS CURTAILMENTS

The existing curtailment scheme is based on the original design criteria of the natural gas system as a whole: that core industrial and electric generation customers have fuel-switching capabilities. This old assumption no longer holds true. These noncore customers have increasingly relied on natural gas over the last 20 years and the use of fuel oil or other petroleum products has been virtually eliminated.³⁷

The CPUC has an open proceeding to examine current natural gas curtailment policies and practices. In general, existing natural gas curtailment rules for PG&E and SoCal Gas were developed for cold winter conditions. In addition, the current rules call for a pro-rata curtailment and diversion of gas from noncore customers when supplies are insufficient to meet winter core peak demand. This means that a set percentage of each customers' needs would not be met, with the percentage of needs that go unmet continuing to ratchet down, until core needs are met.

There is growing recognition that the existing curtailment rules do not factor in the current realities of the market. The curtailment or diversion of natural gas supplies for electric generators could contribute to electricity reliability problems, exacerbating rolling blackouts. In addition, the curtailment of natural gas supplies for industrial customers could exacerbate the economic impacts of anticipated rolling blackouts on their production.

Some electric generators have filed testimony in the CPUC proceeding calling for a modification of curtailment rules that would allow electric generators to be served. Under this scheme, other noncore customers, including industrial customers, would be curtailed before the electric generators were looked to for curtailments or diversions. While this would help reduce the possibility of rolling

³⁷ There are four large gas-fired generators and scores of smaller ones in California that still have the ability to switch to petroleum fuels. The larger facilities include the Humboldt plants on the Northern California coast, the Potrero plants in the Bay Area, and South Bay and Encina plants in the San Diego Area.

blackouts, it also appears to impose unfair economic consequences on industrial customers and the economy as a whole.

The Energy Commission recommends that rather than spending time fine tuning the curtailment rules, it would be more productive to develop and implement new reliability criteria for natural gas utilities to use as a guide in building their systems to meet demand. If done properly, the chances for curtailment would be minimized. In the meantime, the State should see that an efficiency scheme for natural gas curtailments is developed.

One option that might lessen the consequences of natural gas curtailments on both electric generators and industrial customers is a curtailment rule that is tied to the efficiency of the electric generators. Under such a rule, generators with the highest heat rates (the least efficient generators in the system) would be curtailed first. The generators with the lowest heat rates (the most efficient generators on the system) would be the last to be curtailed. Of course, power plants that are required for reliability purposes may have to be given a higher priority than other plants, regardless of heat rate. This curtailment scheme would result in a more efficient use of natural gas in the two gas utility systems, thereby conserving more of the available natural gas supplies for use by industrial customers. This would also provide air quality benefits as the least efficient plants also tend to be the most polluting plants.

NONCORE USE OF UTILITY STORAGE

Under the "unbundled" environment in California, noncore customers, such as electric generators, can use a portion of the natural gas utilities' storage facilities for their own use. In return for that flexibility, noncore customers are required to more closely balance the amount of natural gas nominated and the amount that is actually consumed. As storage levels decline, balancing requirements also tighten, increasing the penalties for non-compliance. During peak generating days, generators may be willing to pay these penalties since the added costs could be recouped through prices charged for electricity.

The Energy Commission is concerned that noncore customers could repeat the storage behavior of last year where it was under-utilized by noncore customers. Rebundling of the utility storage functions was proposed as a means of optimizing the use of storage for noncore customers. The Energy Commission has reconsidered this proposal and has rejected it.³⁸ Several parties at the Electricity & Natural Gas Committee's June 5 hearing reported that this year the noncore customers have learned their lesson from their experiences last year. Storage injections are much better than last year.

³⁸ At its June 5, 2001 Natural Gas Infrastructure Issues Hearing the Energy Commission received testimony from a cross section of the industry against utility storage function rebundling.

Even so, the Energy Commission remains concerned about assuring that natural gas storage use in the State will be optimized based solely on this year's storage behavior. Experience in energy markets shows that lessons learned may soon be forgotten. Alternatives other than commodity futures contracts are needed as hedging strategies. Options to assure adequate storage for electric generators would include the following:

- The ISO could require natural gas storage for RMR power plants to meet annual/seasonal generation.
- The ISO could offer contracts to generators that allow for the recovery of storage costs.
- The DWR contracts could require storage.
- The FERC could require storage through its regulatory powers.
- The Energy Commission siting conditions for new power plants could require a level of storage to meet corresponding demand.
- The CPCFA could invest in or acquire natural gas storage for electric generation.
- The Energy Commission, the CPUC and the FERC could investigate ways to encourage a secondary storage market.
- The CPUC could provide greater incentives to store by tightening up the utility balancing rules.

ENCOURAGING INDEPENDENT GAS STORAGE FACILITIES

Noncore customers can currently store gas in independent storage facilities in Northern California with the now open Wild Goose storage facility, and the Lodi storage facility expected to be operational later this year. Currently, there are no independent storage facilities in Southern California.

The Energy Commission believes that there is value in having independent storage facilities in California. Obviously, they would be available to reduce curtailments. Additionally, they would be developed without adding to the utility rate base. Independent storage promotes competition with the utility owned storage, thereby reducing everyone's cost to use storage.

The State should investigate the prospects for developing additional independent storage facilities throughout California. These facilities should be available to all that would elect to use them. This storage could be used to meet peaking needs as well as for economic reasons. A secondary storage market should also be encouraged. In this manner, competition may be developed, leading to potentially lower storage costs for all customers.

CHAPTER 7 – NATURAL GAS PRICES

OVERVIEW

This chapter addresses natural gas pricing issues and their relationship to pipeline infrastructure.

In the year 2000, natural gas prices rose dramatically throughout the United States, driven by a variety of factors that are described below. In no other place was this increase more apparent than in California, where consumers experienced dramatic price spikes on numerous occasions. California border prices often exceeded \$10 per MMBtu and actually peaked at \$60 per MMBtu last year.

As explained in this chapter, the Energy Commission believes that high natural gas demand overwhelmed the intrastate natural gas infrastructure. This level of demand coupled with peaks in demand upstream of California also exceeded the capacity of the El Paso pipeline system at times. This played a key role in contributing to the high natural gas prices experienced in California during 2000 and the first few months of 2001. Throughout much of the winter 2000-2001 period, the interstate pipelines serving California were fully utilized to the limit of the receipt capacity of Southern California. As a result, intrastate pipelines in Southern California were bottlenecked

Additionally, SoCal Gas started the winter with very low storage level. This occurred because the El Paso pipeline rupture impacted SoCal Gas' summer storage operations. In addition, for economic reasons, noncore customers were reluctant to place natural gas into storage. This resulted in low storage levels available for the winter heating season.

Many have argued, including the CPUC, that entities holding large levels of interstate pipeline capacity caused gas prices to increase by exercising market power and withholding capacity. In their defense, those parties claim that market forces caused the increases in natural gas prices. These arguments were taken to the FERC for consideration. Hearings have been held and an initial decision from the FERC administrative law judge is due on October 9, 2001. The judge has asked the parties to attempt to settle the issue prior to his initial decision.

At the wellhead, gas prices increased in connection with low supply availability and the added push for additional natural gas supplies. This impacted natural gas prices across the nation. Driven by increased power generation needs, producers are now investing heavily in drilling and exploration, as evidenced by the large increase in the number of active drilling rigs throughout North America.

In May, the staff draft report stated:

"We believe that California will not continue to experience the combination of high gas prices and price volatility this coming winter. Improvements in delivery and receiving capacity, as well as ongoing storage system enhancements, will help meet winter gas consumption needs while providing for more flexibility in supply choices. As such, California border prices should be more in line with the rest of the nation. Additional pipeline expansions should reduce the transportation premiums that California has experienced over the past year. Over the next several years, the U.S. and California should see natural gas prices decrease at the wellhead as drilling results bring more natural gas production to the market place."

The Energy Commission is happy to report that the prediction in the staff report was accurate. Natural gas prices are lower at the wellhead and at the California border.

NATURAL GAS PRICES

Figure 7-1 compares natural gas volume-weighted average spot prices at Henry Hub in Louisiana with prices posted at Topock and Malin. Henry Hub is a major gas hub, and commodity futures contracts for gas at Henry Hub trade on the New York Mercantile Exchange. Henry Hub is reflective of prices at the wellhead. As shown in the figure, prices at the California border spiked significantly during peak demand days in 2000 and early 2001. Price spikes are no longer anticipated throughout the remainder of this year and the winter of 2002, in part because SoCal Gas and PG&E have met their storage targets for the upcoming winter peak season.

Topock and Malin are the trading hubs at the California-Arizona and California-Oregon borders respectively. The Topock price represents the Southern California cost of natural gas delivered from Southwest production areas. The Malin price reflects Northern California prices for natural gas originating in Canada. Southwest supply is considered to be the marginal California supply and therefore generally sets the California border prices. In general, the Malin price will track the Topock price, but will usually be a few cents lower.

The higher prices at Topock, shown in **Figure 7-1**, reflect in part the bottleneck caused by the inadequate receipt capacity in Southern California. The higher prices at Topock also reflect the greater concentration of gas-fired power plants in Southern California and the high utilization of the interstate pipelines serving Southern California. Additionally, the August 2000 El Paso interstate pipeline explosion, that vastly limited the amount of gas flowing to California from the

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³⁹ California Energy Commission Staff Draft Report, *Natural Gas Infrastructure Issues*, May 2001, #P200-01-001

Southwest last summer, still accounts for a 20 percent loss of capacity on the company's southern system over one year after the mishap. High Topock prices may also reflect price manipulation by marketers that control rights to ship on those pipelines as alleged by the CPUC and other market participants.

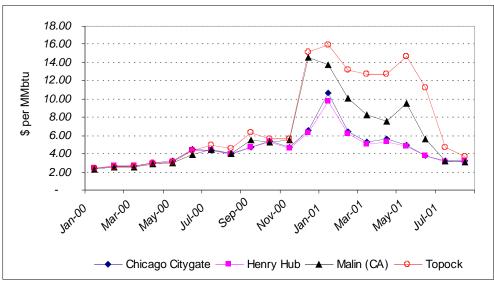


Figure 7-1
Average Monthly Natural Gas Spot Prices

Source: Natural Gas Intelligence

In December 2000 a huge price increase occurred in California, followed in January 2001 by an increase in prices across the rest of the nation. Large price differentials developed between Northern and Southern California. Northern California prices increased to \$14.58 per MMBtu and Southern California prices jumped to \$15.14 per MMBtu. During the succeeding months the differentials grew from \$2.00 in January 2001 to over \$5.00 for several months in the spring and early summer.

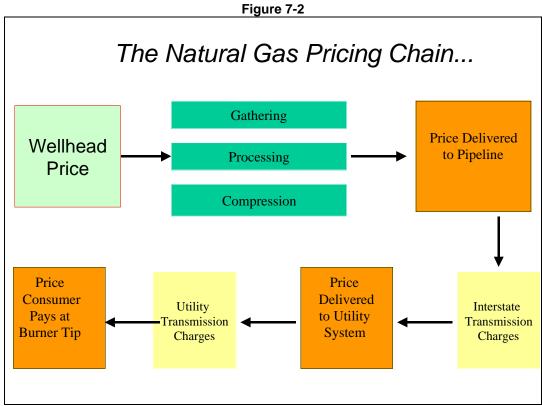
Since May 2001, natural gas prices have been dropping consistently. July 2001 prices have been substantially lower than last year's prices for July. In August 2001, differentials between the two California utilities were back to near normal. Several factors driving down prices include high levels of storage, a sharp reduction in gas demand from gas-fired electric generators, major efforts to conserve energy, and recent decisions at the FERC and the CPUC allowing for additional pipeline capacity and storage for all sectors.

NATURAL GAS PRICE COMPONENTS

Given the integrated nature of the natural gas infrastructure, natural gas prices in California are impacted by prices in other parts of the United States and Canada. Wellhead production in West Texas affects California gas prices, as does production in the Gulf Coast, Canada, and the Rocky Mountains.

California gas prices are also affected by transmission charges levied by the many interstate pipelines delivering natural gas from the wellhead to California, as well as the transmission and distribution charges assessed by utility and non-utility distributors inside the State.

Figure 7-2 illustrates the natural gas pricing chain described above. Gas that is produced in the production basin is referred to as wellhead production. The gas is then processed (to ensure pipeline quality gas enters the gas system), compressed, and delivered to the gathering system attached to the gas pipeline network.



Source: California Energy Commission

The resulting *price delivered to the pipeline* is the price of natural gas delivered to an interstate or intrastate pipeline once the gas has been produced, treated, and gathered. For gas moving to California, it represents a price in the Rocky Mountains, the San Juan Basin, the Permian Basin, or Western Canada.

Normally, interstate pipeline transmission charges are added to the wellhead price to obtain the California border price. Subsequent additions accounting for utility transmission charges (including distribution costs) will eventually produce a price that each consumer will pay at the burner tip for using gas, with variations based on the customer classification.

In California the average price for natural gas paid by the State's consumers increased roughly 70 percent from December 1999 to December 2000. The average price paid by PG&E residential customers increased about another 60 percent from December 2000 to January 2001.

The average prices paid by commercial, industrial and electric generator gas consumers is not currently available to the public. At this time, these customers can buy their own gas supplies and are not required to report the prices they pay for natural gas. The Energy Commission recently began collecting price data from gas marketers serving California. In addition, all electric generators above one MW are also required to report to the Energy Commission the quantity and cost of natural gas consumed.

FACTORS AFFECTING CALIFORNIA NATURAL GAS PRICES

During late 2000 and early 2001, increases in wellhead prices, gas-fired electric generator demand and premiums in interstate transmission charges increased gas prices in California substantially.

This section divides the discussion to first address factors affecting the wellhead portion of California's gas prices; factors that apply to all gas consumed in the United States. The second section addresses increases in gas-fired electric generator demand. The third section addresses the *premium* added to interstate transmission charges to ship gas to California. The size of the premium currently charged for gas shipped to California during last winter was not charged in other markets in the United States.

Wellhead Prices

Wellhead prices are affected by a variety of factors, but they are driven by the need to satisfy growing natural gas demand. As discussed in *Chapter 3*, the growth in supply did not keep up with demand growth in North America during the 1990's due to expectations of low natural gas prices. As a result, in 1999, the number of active drilling rigs reached a historic low.

This situation changed dramatically in 2000 along with the sharp increase in natural gas demand. Several factors contributed to this increase. As the winter of 1999-2000 ended, the nation's storage levels were abnormally low. To meet the coming winter needs (2001-2002) the demand for natural gas to place into storage was very high. In addition, a strong economy and increased demand for natural gas to power electric generators also added to the demand in 2000. There was insufficient gas supply from imports and U.S. production to meet both needs.

The result of a decade of low levels of drilling, topped off with unusually high levels of demand was a jump in natural gas prices. As evidenced by **Figure 7-3**, annual average spot prices at the Henry Hub increased significantly in the year 2000. Prices were at or above that amount for the first half of 2001. There has

been a recent return to prices tied closer to production costs as storage injection exceeds market expectations on a national basis and national electric generation demand has continued to be lower than last year.

Annual Spot Prices - Henry Hub 5.00 4.34 4.50 4.00 3.50 \$/MMBtu 3.00 2.76 2.57 2.25 2.50 2.11 2.08 1.86 1.80 2.00 1.50 1.00 0.50 0.00 1993 1994 1995 1996 1997 1998 1999 2000

Figure 7-3

Source: Natural Gas Week, April 21, 2001

Electric Generation Demand for Natural Gas in California

Power plants are a major consumer of natural gas in California. In 2000, power plant fuel use consumed about 40 percent of natural gas supply. As **Figure 5-4** in **Chapter 5** indicates, gas demand last winter for electric generators was two to nearly three times the normal winter gas demand in Southern California. This winter gas demand was more consistent with average summer electric generation gas demand.

As previously discussed in *Chapter 3 & 5*, the demand for natural gas to power electric generation increased significantly in California due to decreases in imports of electricity from neighboring states. The decline in imports is due to adverse hydro conditions in the western United States and increased demand for electricity in the West. As a consequence, the surrounding states have less effective generating capacity and are using more of what capacity they have to meet their own needs. California was forced to rely on the old and inefficient power plants in the State to meet its citizen's electricity needs.

Merchant power plants in California had no economic, and in most case no physical, alternative to burning natural gas. Due to past economics and air emission regulations they only have the capability of burning natural gas. Even the few that do have alternative fuel capability can not switch fuel for economic

reasons, but are allowed by air quality regulations to switch only when natural gas service is curtailed. Therefore, in order to meet the electricity demand and avoid blackouts, the generators needed gas supply at virtually any price. Since generators were able to pass those costs on to consumers they were willing to pay extremely high prices.

The deregulation of electric generation in California contributed to the high price of natural gas compared to the rest of the United States. The deregulation scheme adopted by California required all the merchant power plants to bid into a spot market. When drought conditions were experienced and generation supply became tight the merchant power plants were able to set the price for electricity. Knowing they would receive whatever price necessary to cover their costs, the merchant generators became indifferent to the price for natural gas. This dynamic was a major contributor to the extraordinarily high natural gas prices.

Without the increased demand for natural gas by electric generators in California and resulting high utilization rates for natural gas infrastructure, it is unlikely that the premiums charged to ship gas to California would be nearly as high as they were in late 2000 and early 2001.

Interstate and Intrastate Pipeline Capacity Premiums

The relationship between pipeline utilization and the cost of shipping natural gas is relatively straightforward: Costs remain low as long as adequate pipeline capacity and choices are available to consumers. High pipeline utilization causes premium prices because, without slack capacity in the pipeline system, there is limited ability to use gas-on-gas competition to influence prices.

As discussed in the previous chapters on interstate and intrastate pipelines, efforts are underway to expand pipeline capacity. As the market has recently demonstrated, once consumers have options and marketers compete, the premium charged last winter has been eliminated.

STORAGE

For purposes of understanding pricing impacts in California, storage can be considered an extension of the pipeline infrastructure. Thus, when storage availability declines or when storage is depleted, and it is not available to offset pipeline flow natural gas, prices rise. In the year 2000, storage inventories in the SoCal Gas and PG&E service territories were under-filled during the summer injection season. Last August, an explosion on the El Paso pipeline limited supply deliveries to SoCal Gas. This had a double impact on the utility. Prior to the explosion the utility was already withdrawing high levels of gas from storage to meet high demand by gas-fired generators. After the explosion, SoCal Gas increased storage withdrawals by about 200 MMcfd to make up for the lost supply. PG&E storage was affected by the decision of noncore customers, particularly electric generators, to not put gas into storage and in some cases to withdraw some or all of the supply they had already placed in storage.

As a consequence, the 2000-2001 winter withdrawal period began at excessively low levels and ultimately declined to historically low levels. In fact, because of abnormally cold weather in November and December, energy officials were concerned about whether there would actually be enough gas available from storage during January, February and March. This uncertainty reinforced the premiums for natural gas in Southern California.

Normally, storage may be used as a supply option to help mitigate high prices for flowing gas supply. During this past winter this option was not available. To meet customer demand, continuous heavy storage withdrawal was needed to meet SoCal Gas customer needs. For storage to effectively offset the high prices its customers were paying for pipeline supply, even more gas would need to have been withdrawn. Noncore customers had insufficient stored gas to do this. Because of the low storage levels SoCal Gas was only able to assist to a level that insured supply met demand. There was insufficient gas in storage to act as an alternative to pipeline gas and thereby limit shipping premiums on the pipelines.

Throughout the winter PG&E pipeline supply was below its firm capacity. This helped to keep its customer prices lower than those in the SoCal Gas service area. Because of its financial conditions, PG&E had little opportunity to use storage to offset high priced supply for its core customers. Credit worthiness made it difficult to purchase enough gas to meet its basic core customer demand. Storage became a backup supply to meet not only peak cold weather needs but also to meet flowing supply needs when purchases for core were inadequate.

As discussed earlier, efforts are underway to expand the storage capability in California.

CONCLUSION

Infrastructure inadequacies resulting from high demand and low natural gas storage levels contributed to high gas prices and gas price volatility in 2000 and early 2001. The Energy Commission is optimistic that steps being taken will mitigate these inadequacies. The number of drilling rigs in-use has increased, and correspondingly, the supply of natural gas should increase. Interstate pipeline companies are responding to demands for more capacity; the pipeline capacity serving California should increase. Intrastate receipt facilities are being expanded and should ameliorate the premium charged to California customers. Storage facilities are being optimized and expanded. Increased pipeline capacity planned and underway and expanded storage facilities should allow consumers to use gas-on-gas competition, reducing opportunities for charging premiums for natural gas in the future.

APPENDIX A – EXISTING INTERSTATE PIPELINES AND PROPOSED EXPANSIONS

INTERSTATE PIPELINES CONNECTED TO SUPPLY BASINS

PG&E Gas Transmission-Northwest and Tuscarora Pipelines

PG&E Gas Transmission-Northwest (GTN) is a PG&E National Energy Group company. GTN extends from the Canadian border at Kingsgate, Idaho, to the California-Oregon border at Malin. The capacity at Kingsgate is about 2600 MMcfd and declines as it moves south due to compressor capability. The capacity at Malin is about 1900 MMcfd. The Tuscarora pipeline extends from Malin to Reno, Nevada, with a capacity of 125 MMcfd.

GTN connects to the PG&E pipeline system at Malin. The receipt capacity at Malin is rated at 1900 MMcfd. Thus, the physical capacity of the delivery and receipt at Malin match. However, upstream demands in the Pacific Northwest limit the amount of gas that is delivered to California at Malin.

The reductions in the delivery to California occur when upstream customers sign firm transportation contracts to serve increased demands. For example, when GTN built the Tuscarora pipeline it began drawing 125 MMcfd of capacity that used to be available to serve California. On February 12, 2001, Tuscarora Gas Transmission Company filed with FERC to expand Tuscarora by 96 MMcfd. This expansion will draw capacity from PG&E-GTN to serve Dodge Flat and Tracey power plants and other customers in Nevada.

In addition, the gas utilities serving the Northwest have provided for the increased demand caused by population and economic growth in Oregon and Washington. Also, a number of gas-fired power plants recently constructed, or about to come on line, in the Pacific Northwest have arranged for firm transportation to serve their needs.

Cold weather also affects the capability of the GTN pipeline to serve California. If extreme cold weather strikes the Pacific Northwest, the local demand will draw off an additional 350 MMcfd from the GTN pipeline before it reaches California. In all likelihood, this will occur on a day that California experiences its own peak cold weather demands. If extreme weather conditions freeze wellheads in Canada, the reduction in deliveries to California would be even more extensive.

In the long term, as gas resources are consumed and new pipelines to other regions of the United States are added, Western Canada may become a less

reliable source of natural gas for California. Recently, the Alliance pipeline started carrying 1300 MMcfd from Alberta to Chicago.

In both the near- and long-term, the supply of natural gas from Canada to California is at risk from actions that occur upstream. To evaluate this risk, the Energy Commission should determine whether the natural gas-fired power plants in the Pacific Northwest would displace similar plants in California. The Energy Commission should also forecast total natural gas use along the interstate pipeline from Canada. In addition, the Energy Commission should quantify the effect of cold weather in Canada and the Pacific Northwest on deliveries to California.

Kern River Pipeline

Kern River Gas Transmission Company ("Kern River") is a Williams Company pipeline. Kern River originates in Wyoming, crosses Utah and Nevada, and then merges with the Mojave pipeline at Daggett, California, to form the Kern/Mojave pipeline. Kern River began operations in 1992. The delivery capacity at Daggett is 700 MMcfd. Kern River connects directly with PG&E at Daggett.

In California, Kern River has four principal customers. Kern River can deliver 350 MMcfd to the PG&E system. Additionally, Kern serves the Cool Water electric generator. Through Kern/Mojave, gas is delivered to enhanced oil recovery operations and the associated co-generation facilities. At Wheeler Ridge, gas is delivered into the SoCal Gas system.

Kern River currently delivers only about half its original design capacity. The Kern River pipeline is still physically capable of delivering the original design capacity of 700 MMcfd. During the past winter, only about 450 MMcfd of natural gas supply reached California because customers in the Las Vegas, Nevada area, including electric generation, are now drawing from the pipeline before it reaches California.

Figure A-1 shows proposed power plants along the Kern River system, including the Kern/Mojave extension. If all these power plants were built, they would draw over 2000 MMcfd of natural gas.

The Energy Commission should continue to monitor the gas acquisition plans of applicants before the Energy Commission proposing to rely on the Kern River pipeline and continue to assure that the approved plants have adequate access to natural gas.

Transwestern Pipeline

Enron owns the Transwestern Pipeline ("Transwestern"), which stretches from West Texas to the California/Arizona border at Needles. Transwestern can deliver natural gas from the San Juan, Permian and Anadarko basins. In the

year 1992, Transwestern put an expansion into service that increased firm capacity to 1050 MMcfd.

Through a lateral pipe, Transwestern can deliver gas to PG&E and the Mojave pipeline at Topock. Currently, SoCal Gas and marketers have firm contracts to receive 750 MMcfd of the Transwestern capacity at Needles, and PG&E and marketers have firm contracts to receive 300 MMcfd at Topock.

Figure A-1

Pastoria - Enron (750 MW)

High Desert - Constellation (720 MW)

La Paloma - PG&E (1050 MW)

Elk Hills - Oxy/Sempra (500 MW)

Sunrise - Mission Energy (320 MW)

Midway Sunset - Midway Cogen (500 MW)

Antelope Valley - Enron (1000 MW)

Apex - Mirant (1150 MW)

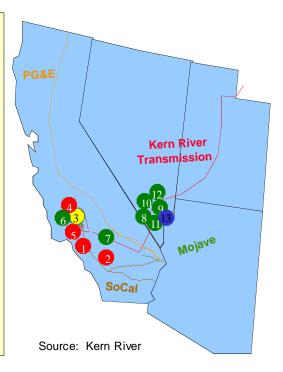
Moapa - Duke (1200 MW)

Meadow Valley - PG&E (1000 MW)

Arrow Canyon - Reliant (500 MW)

Crystal - Calpine (760 MW)

El Dorado - Reliant/Sempra (480 MW)



El Paso Pipelines

El Paso Corporation owns the El Paso Pipeline Group ("El Paso"). El Paso is divided into a Northern and a Southern System. The two systems are connected by the Havasu crossover and are both able to deliver natural gas from the San Juan, Permian and Anadarko basins to California. Besides serving customers in New Mexico, Arizona, and Nevada, the Northern System delivers 2080 MMcfd of nominally firm capacity to Topock. Additionally, the Southern System delivers 1240 MMcfd of nominally firm capacity to Ehrenberg, Arizona, located across the Colorado River from Blythe, California.

The capacity to receive gas from El Paso's Northern System is divided as follows:

- PG&E 1140 MMcfd:
- SoCal Gas 540 MMcfd; and
- Mojave 400 MMcfd.

SoCal Gas has the capacity to receive the entire 1240 MMcfd of firm capacity at Ehrenberg. If pressures are high enough (due to high demand in Southern California), SoCal Gas is able to receive an additional 200 MMcfd at Ehrenberg.

El Paso has testified at FERC that this last winter it was unable at times to deliver its total firm capacity to the California border due to upstream demands. This means that California is not receiving all of the firm capacity that it pays El Paso to provide. Since El Paso continues to add customers upstream of California, this warrants analysis of the potential damage to California due to the failure of El Paso to honor its commitment to provide firm capacity to California.

INTERSTATE PIPELINES NOT CONNECTED TO SUPPLY BASINS

Mojave and Kern/Mojave Pipelines

The El Paso Corporation owns the Mojave Pipeline Company ("Mojave"). Mojave originates at Topock, Arizona. Topock is on the California-Arizona border where Interstate 40 crosses the Colorado River. Mojave has a capacity of 400 MMcfd from a combination of receipts from El Paso and Transwestern at the California border. It joins with Kern River at Daggett to form the Kern/Mojave pipeline. Mojave and Kern/Mojave are bypass pipelines.

Mojave may receive the full 400 MMcfd of its capacity from the El Paso Northern system at Topock. Mojave may elect to take less than 400 MMcfd from El Paso and up to 150 MMcfd from Transwestern, as long as the total does not exceed 400 MMcfd.

Kern River and Mojave own about 64 and 36 percent, respectively, of Kern/Mojave. Kern/Mojave originates at Daggett and continues northwest into Kern County. Kern/Mojave then divides in two with laterals running up the east and west sides of the lower San Joaquin Valley to serve enhanced oil recovery customers. Kern/Mojave has a capacity of 1,100 MMcfd.

Kern/Mojave has a spur that connects with Wheeler Ridge, a receipt point for SoCal Gas. Kern/Mojave supplies about half of the 760 MMcfd capacity at Wheeler Ridge.

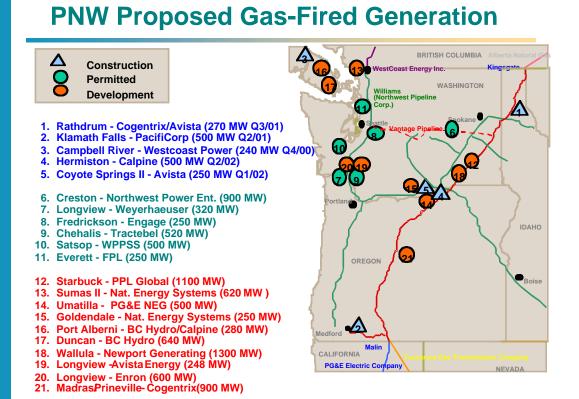
Mojave delivers to SoCal Gas at Hector Road and has direct deliveries to industrial customers such as U.S. Borax. Kern/Mojave delivers gas to SoCal Gas at Wheeler Ridge, to PG&E at Daggett, and to the Coolwater power plant and enhanced oil recovery and associated co-generation in the lower San Joaquin Valley. Kern/Mojave is scheduled to deliver gas to electric generators under development such as La Paloma and Sunrise.

INTERSTATE PIPELINE PROJECTS PROPOSED OR UNDERWAY

GTN Pipeline Upgrade

Figure A-2 shows the location of the gas-fired power plants under construction and proposed in the Pacific Northwest. Even with the 200 MMcfd proposed expansion discussed below, the effective delivery capacity to California from Canada will decrease significantly if even a fraction of these plants is constructed and no additional pipeline capacity is added. The plants under construction will consume about 300 MMcfd when operating. If constructed, the plants pursuing permits and under development will consume about 465 MMcfd and 1100 MMcfd respectively. The rough total of all these plants (about 1,865 MMcfd) exceeds the entire receipt capacity into California at Malin.

Figure A-2



Shaded area represents numbers 6-21.

As the result of a recent open season solicitation, GTN has announced an expansion of about 200 MMcfd of additional firm transportation capacity from Canada to California. The additional capacity would originate at the interconnection to the TransCanada Pipeline at Kingsgate and extend to the California-Oregon border at Malin. According to the PG&E National Energy

Group, there was a ten-fold interest in the expansion. This expansion is expected to be available in April 2002. With expedited FERC approval, a portion 42 MMcfd will be available by November for the 2001-2002 winter. An additional 169 MMcfd will be operational by July 2002.

In April 2001, GTN held an open season to determine additional support for new capacity to be available in 2003. GTN has not yet announced its plans for 2001; however, they have announced that over the next 10 years, they anticipate adding 1,000 MMcfd in new pipeline capacity.

Tuscarora Pipeline Upgrade

The Tuscarora Pipeline Company filed an application with FERC to expand the existing 125 MMcfd Tuscarora pipeline by an additional 96 MMcfd, to be in service by early 2003.

Kern Pipeline Expansions

The new natural gas-fired generation in Nevada and California caused Kern River to initiate expansion efforts. These proposed gas-fired generators are shown in **Figure A-1**. Kern River has already awarded allocations on a first expansion of 146 MMcfd that is expected to be online in May 2002.

To satisfy the immediate needs of electric generators in California for interstate gas shipping capacity for the summer of 2001, Kern River filed for an emergency expedited review at FERC for 135 MMcfd of new capacity, which was made available in July 2001. Ninety-five percent of this capacity was awarded to shippers for delivery to Wheeler Ridge. The expansion included adding temporary compression facilities. Permanent facilities will be installed, pursuant to the FERC filing, for the 146 MMcfd expansion.

A second open season drew about 2000 MMcfd of interest for a second 300 MMcfd expansion. Based on this, Kern River has announced that it will be expanding its system by 906 MMcfd for operation by May 2003. This new capacity will require 400 miles of new pipeline and additional compression. The increased volume will principally serve new power generation.

Kern River also plans to extend by September 2002 their Kern/Mojave pipeline from Daggett to Victorville by building a 282 MMcfd lateral pipeline.

Kern/Mojave Pipeline Expansion

The 135 MMcfd emergency expansion approved by FERC for Kern River includes compression at Daggett. This additional compression will increase the capacity on Kern/Mojave as well by an additional 135 MMcfd. The Kern River proposal to expand by 900 MMcfd would require additional compression on Kern/Mojave.

Transwestern Pipeline Expansion

On March 29, 2001, Transwestern filed an application with FERC to expand its system by 150 MMcfd. FERC approved the expansion in June 2001 and Transwestern plans to have a pipeline in operation by June 2002. This expansion would serve both California and states to the East of California.

El Paso System Expansions

All American Pipeline

El Paso has announced plans to convert the All American Pipeline from an oil pipeline to a natural gas pipeline in mid 2001. El Paso has requested an expedited emergency review by FERC to bring the All American Pipeline into service as a natural gas pipeline. While FERC has approved the conversion, other permits are still pending. El Paso estimates that it could complete the cleaning of the existing oil pipeline and be transporting gas to California by the end of December 2001. Capacity for this pipeline will be 230 MMcfd.

The conversion of this pipeline would provide backup for the El Paso Southern System as various segments are taken off line for scheduled testing and maintenance. The conversion would provide alternative capacity to keep the pipeline system operational during this testing and maintenance.

Open Season Solicitation

El Paso solicited interest in adding new capacity to their pipeline system. Based on the responses to the open season that concluded on March 23, 2001, El Paso has announced that 120 responses requested 9,700 MMcfd in new capacity. Of these, 76 solicitations requested 4,500 MMcfd for delivery to the California border or inside the State.

However, El Paso judged that the response to the binding solicitations did not justify expanding capacity into California. El Paso will also decide whether the All American Pipeline will be increased to 500 MMcfd.

Sacramento Valley Project

One potential expansion by El Paso is the Sacramento Valley Project. On May 11, 2001, El Paso announced that its subsidiary, Mojave Pipeline is holding an open season to provide incremental transportation capacity along an expanded Mojave Pipeline system from Topock to the Antioch and Sacramento areas. The open season was held from May 10 through May 31, 2001. The final decision by Mojave to expand or extend the current system is still pending.

Bi-Directional Lateral Project

In May 2001, El Paso's subsidiary, the El Paso Natural Gas Company, held an open season on a proposed bi-directional lateral between Daggett and Ehrenberg. El Paso proposes to connect its existing Southern system with the

new lateral that will utilize the portion of the former All American Pipeline facilities that extends from Daggett to Ehrenberg. The open season held from May 1 through May 25, 2001 did not generate sufficient interest and the proposal is on hold.

North Baja Pipeline Project

The North Baja Pipeline Project ("North Baja") is a joint effort of Sempra, PG&E National Energy Group and Mexico's Proxima originating at Ehrenberg, traveling south into Mexico east of Mexicali, and then west to Rosarito in Baja California. Just south of the United States-Mexico border from Otay Mesa, North Baja would link with the existing pipeline that receives natural gas from SDG&E for delivery to Rosarito. The proposed capacity of 500 MMcfd is expected to be in service by September 2002, with deliveries of as much as 250 MMcfd as early as July 2002. The North Baja pipeline is intended to serve power plants in Mexico and the Otay Mesa project in San Diego, as well as other demands.

North Baja does not increase access to natural gas producing basins. North Baja will receive natural gas from the El Paso South System at Ehrenberg and deliver it to Mexico and San Diego. When the North Baja pipeline is operational the gas SDG&E is currently providing to the Rosarito Beach power plant in Mexico will be available to serve SDG&E customers. However, to the extent that North Baja serves demands in Mexico not currently served by SDG&E, North Baja will compete for the natural gas pipeline capacity currently serving California.

North Baja reports, in its application to the FERC for permission to build the pipeline, that it signed precedent contracts for about 300 MMcfd. These contracts include about 45 MMcfd of the roughly 80 MMcfd usage of the Otay Mesa project. The remaining 255 MMcfd in contracts will be used for generators (230MMcfd) and for industrial users in Mexico (25 MMcfd).

The application details the market for the remaining capacity. North Baja estimates that there is between 300 to 450 MMcfd of additional generator demand in Mexico, as well as an additional 120 MMcfd of propane conversion and local distribution demand in Mexico.

Apparently, slightly less than 10 percent of the North Baja capacity will serve demands in San Diego. The current 90 MMcfd serving generator demands in Mexico would be displaced and available in San Diego. However, all of the flow on the El Paso system serving California was needed in the summer of 2000. Removing about 350 to 400 MMcfd of capacity from service to California to serve Mexico raises a serious question: Where will California find the interstate pipeline capacity to replace such a significant amount? The simple answer is

that El Paso will potentially have to build more pipeline capacity, provided it receives the necessary transport contracts to support new construction.⁴⁰

The Energy Commission should investigate whether North Baja would force curtailments under conditions as experienced in the summer of 2000, and other plausible scenarios.

Otay Mesa Generating Company Pipeline Project

Otay Mesa recently filed with FERC for construction of a new 110 MMcfd gas pipeline to be completed by September 2002 to connect its proposed natural gas-fired generating facility in San Diego with North Baja in Mexico.

Questar Southern Trails Pipeline Project

Questar Southern Trails Pipeline Company applied, and received permission from the FERC, to convert its existing crude oil pipeline to carry natural gas. Questar Southern Trails runs from the San Juan Basin to the Los Angeles area. The converted pipeline would be able to carry 90 MMcfd to the California border and 120 MMcfd into the Los Angeles area.

Questar announced that it has signed a long-term deal to deliver natural gas on the east zone of the Southern Trails Pipeline. Questar also says it is seeking customers for the west zone that serves California. The portion of the project that serves California is currently on hold until sufficient customer support is generated to make the conversion economically viable.

The major barrier, raising questions about the conversion of the California portion of this project, is a current peaking tariff contained in the existing rates of SoCal Gas. This tariff, referred to as the RLS tariff, makes it uneconomic for customers to seek an alternate supplier to SoCal Gas if the customer intends to have a portion of its needs satisfied via a direct link to an interstate pipeline.

Even though the CPUC changed the RLS tariff, the project still appears unable to compete with the SoCal Gas transportation rates. The current SoCal Gas rate for electric generators is \$0.26/Mmbtu, while the comparable Southern Trails rate would be \$0.39/MMbtu. There may be customers who are willing to pay this extra cost to avoid CPUC regulation and the accompanying diversion rules.

Ruby Pipeline

The El Paso subsidiary, Colorado Interstate Gas, held an open season in May 2001 to evaluate whether it should add pipeline capacity from Western Wyoming

⁴⁰ New electric generation capacity being built in Southern Arizona and New Mexico will also tap into the El Paso system, placing additional needs for the pipeline to meet.

to Nevada and Northern California markets. This new pipeline would add up to 750 MMcfd of capacity that could be in service by December 2004.

Sonoran Proposal

On May 2, 2001, Kinder Morgan Energy Partners and Calpine Corporation announced plans to jointly develop the 1160 mile Sonoran Pipeline from the San Juan Basin in northern New Mexico to California markets in two phases. Phase I contemplates a 36-inch pipeline from New Mexico to Needles with a 24-inch lateral to Topock. The pipeline would initially transport 750 MMcfd. Phase II would consist of approximately 590 miles of 36-inch and 42-inch pipeline from Needles to Antioch. Phase II would transport from 1000 to 1500 MMcfd depending on shipper interest.

APPENDIX B – NATURAL GAS AND PEAK ELECTRIC GENERATION

OVERVIEW

To assess potential peak demand for natural gas for the year 2001, the Energy Commission prepared a peak natural gas demand forecast for the natural gas utility service areas.

This appendix presents the results of the Energy Commission's analysis of natural gas infrastructure capacity to support natural gas demand by electric generators during peak week operations in the summer of 2001. A motivation for this analysis was that California was embarking on an ambitious program to bring additional gas-fired electric generating capacity on-line for the summer of 2001. This analysis does not include gas demand by back-up generators.

PG&E PEAK SUMMER WEEK ANALYSIS

Table B-1 presents the peak summer week natural gas demand for the PG&E service area. To provide a high gas use scenario, one of the units at the Diablo Canyon Nuclear Power Plant is assumed to be on a forced outage during the week. This outage causes additional natural gas-fired generators to run, adding from 50 to 100 MMcfd to the total gas demand. The demand on a daily, average basis is about equal to PG&E's capacity to receive supply into its service area. Some natural gas from storage is likely to be needed to sustain the supply for meeting all the demand.

Table B-1 – PG&E Service Area Peak Summer Week Natural Gas Demand One Unit at Diablo Canyon is Forced Out MMcfd						
Day	Core	Noncore	Off System	Electric Generation	Total	
Monday	449	701	350	1,606	3,105	
Tuesday	449	701	350	1,618	3,117	
Wednesday	449	701	350	1,668	3,167	
Thursday	449	701	350	1,153	3,029	
Friday	449	701	350	1,541	3,040	
Saturday	449	701	350	1,427	2,926	
Sunday	449	701	350	1,326	2,825	

Notes:

- Supply Capacity is 3,200 MMcfd
- Peak week occurs in August

SOCAL GAS PEAK SUMMER WEEK ANALYSIS

Table B-2 presents the peak summer week natural gas demand for the SoCal Gas service area. Substantial quantities of supply from storage would be needed to insure sufficient supply to meet power plant needs.

Table B-2 So Cal Gas Service Area Peak Summer Week Natural Gas Demand MMcfd					
Day	Core	Noncore	Electric Generation	Total	
Monday	709	783	2,304	3,796	
Tuesday	709	783	2,588	4,080	
Wednesday	709	783	2,487	3,979	
Thursday	709	783	2,487	3,979	
Friday	709	783	2,445	3,937	
Saturday	709	783	2,138	3,630	
Sunday	709	783	1,767	3,259	

Notes:

- Includes deliveries to SDG&E and Rosarito Beach Power Plant
- Supply Capacity is 3,500 MMcfd with an additional 200 MMcfd possible
- Peak week demand occurs in August

SDG&E PEAK SUMMER WEEK ANALYSIS

Table B-3 presents the peak summer week natural gas demand for the SDG&E service area. On a daily, average basis, the natural gas capacity would meet the peak week demand.

Table B-3 SDG&E Service Area Peak Summer Week Natural Gas Demand MMcfd						
Day	Core	Noncore	Electric Generation	Rosarito	Total	
Monday	107	14	320	116	557	
Tuesday	107	14	334	113	568	
Wednesday	107	14	361	87	569	
Thursday	107	14	329	100	550	
Friday	107	14	317	97	535	
Saturday	107	14	278	75	474	
Sunday	107	14	201	57	379	

Notes:

- Supply Capacity will be 665 MMcfd
- Peak week demand occurs in August

PEAK HOUR DEMAND ANALYSIS FOR UTILITIES

The peak summer hour demand for each of the utility service areas is shown in **Table B-4**. Each of the utilities total demand exceeds flowing supply. For both the PG&E and SoCal Gas service areas, storage facilities are available to meet the demand if the electric generators have placed natural gas into storage. SDG&E does not have storage available to meet its demand. Staff analysis of hourly peaks indicates that daily shortages would be less than the operational

supply that SDG&E may "pack" into its system.⁴¹ With proper maintenance of the pack and draft supply SDG&E should be able to meet this summer's peak hour and daily demand. This may require some coordination between the natural gas utility, electric generators and ISO dispatchers. In the unlikely event that this does not work, SDG&E would have to resort to curtailing the electric generators on its system. These generators have the capability for burning fuel oil.

Table B-4 Peak Summer Hour Natural Gas Demand Forecast MMcf per Hour						
Service Area	Electric Generation	Non-Electric Generation	Total	Pipeline Capacity	Supply Shortfall	Storage Withdrawal Capacity
PG&E	92	63	155	133	(21)	63
SoCal Gas	160	58	218	150	(69)	133
SDG&E	28	5	33	27	(6)	NA

Notes:

- SoCal Gas deliveries include SDG&E and Rosarito Power Plant
- SDG&E includes Rosarito Power Plant
- SDG&E supply shortfall could be met using system inventory from pack and drafting the system.

⁴¹ A quantity of natural gas supply may be stored in the utility pipeline system. By "packing" or increasing the pipeline pressure SDG&E can store up to 64 MMcf in its system. When demand increases it may "draft" or withdraw that supply from the system.

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APPENDIX C: SUMMARY OF PARTIES COMMENTS

OVERVIEW

The following presents a summary of the major issues raised by parties in comments on the staff draft report. They are arranged according to the following general themes:

- Gas infrastructure improvements,
- Natural gas storage issues,
- Electricity and storage analysis,
- Planning and design criteria,
- Curtailment rules, and
- In-state natural gas production.

An additional section has been added to this appendix summarizing parties comments received on the Electricity & Natural Gas Committee's August, 2001 Draft Final Report.

GAS INFRASTRUCTURE IMPROVEMENTS

Federal Energy Regulatory Commission (FERC)

- FERC agreed with the general conclusion of the report that the natural gas system in California is strained in meeting growing demand, especially for gas-fired electric generators. They also agreed that it is important for the State to ensure that adequate intrastate capacity exists to serve the needs of California consumers.
- FERC concurred with the report's conclusion that the proposed plans to improve California's natural gas infrastructure are extremely important and they were encouraged that the report recommended supporting intrastate system expansions and exploring the role that enhanced storage can play in meeting future demand.
- FERC suggested that in addition to inadequate infrastructure there may be other contributing factors that should be addressed. These include factors such as the inability of some electric generators being served by California utilities to obtain firm capacity rights to the utilities "backbone" systems or firm/flexible rights to the utilities' receipt points. Another contributing factor may be tariff provisions that result in disincentives for noncore customers and electric generators.
- FERC suggested the Energy Commission examine in more detail the extent to which the current intrastate regulatory environment discourages electric generators from attaching themselves to the intrastate gas transmission and distribution systems, and how a nondiscriminatory open access transportation program for all customers could enhance California's natural gas transportation infrastructure.

- FERC agrees with the Energy Commission staff that slack pipeline capacity is beneficial in achieving price stability in deregulated gas commodity markets. FERC suggested consideration of the economic impacts of slack capacity on capacity values, the willingness of shippers to contract for firm capacity in surplus capacity conditions, and rate mechanisms that may be appropriate, to keep the local distribution companies whole if slack capacity is built but cost recovery remains on a volumetric basis.
- FERC suggests it would be helpful to examine intrastate tariffs in more detail to identify and recommend elimination of anti-competitive provisions.
- FERC recommends the Energy Commission explore the distinction between shortage price premiums, price manipulation potential, and market dynamics, particularly the demand elasticity of gas customers and whether electric generators have any real demand response to gas prices.

Duke Energy

- DENA's primary focus is on the current inadequacy of natural gas infrastructure that is most acute in San Diego, where curtailments of natural gas to electric customers (including South Bay plant) have occurred and are expected in the future.
- DENA supports the Line 6900 expansion (70 MMcfd) in SoCal/San Diego area and North Baja to provide service to northern Mexico as an additional source of supply to San Diego.
- However, DENA notes that the practical impact of alleviating constraints that are impairing electric reliability remains unclear, because the demand by Rosarito electric generating station could consume all of expansion in near term until North Baja is completed.
- Also North Baja could divert supply away from SoCal Gas and the San Diego area.
- DENA supports increased take-away capacity for Southern California loads and increased receipt capacity at the California border to create slack capacity.
- DENA suggests that regulatory changes that might facilitate construction of intrastate projects include confirmation of a statewide basic reliability standard for service to electric generation demand such as 1 day in 10year outage probability. This would include an obligation on the part of the gas utility to ensure that natural gas infrastructure is in place, consistent with the standard, and that the utility will recover associated costs.
- DENA states that Line 6900 expansion was unnecessarily delayed because of new cost allocation theories and that cost allocation and collection issues remain unsolved.
- They note that the desirability of improving the transportation system was reinforced at the CPUC April 17 workshop by PG&E data comparing the relatively small cost of transportation system upgrades to the much higher costs associated with the effect on delivered gas prices when transportation capacity is tight.

PG&E Company

- PG&E states that use and expansion of existing utility intrastate facilities would best serve the interests of California consumers.
- Expansion of Redwood Path has an incremental cost of about 10 cents per million Btu; much cheaper than the cost of building new pipeline to increase access to historically low cost gas supply from Western Canada.
- PG&E has announced an open season for backbone transmission capacity to determine market interest in expanding Redwood path. The current expansion would add at least 200 MMcfd and PG&E could expand another 300 or more depending on market interest. (200-500 MMcfd expansion cost is about \$30-100 million.)
- PG&E notes that there need to be clear guidelines for infrastructure expansions and cost recovery to facilitate construction of needed intrastate expansion projects.
- PG&E suggests shortening and simplifying the regulatory approval process for projects. Current legislation would raise project cost triggers for a Certificate of Public Convenience and Necessity (CPCN) from \$50 to \$100 million.

PG&E National Energy Group (PG&E NEG)

- PG&E NEG provided comments on the staff report's assertion on p. 73 "...if there are no firm capacity contracts on El Paso to serve the increased demand there will be no flow on the North Baja Pipeline." PG&E NEG says there will be significant deliveries made by North Baja from the moment it begins commercial operations. In addition, an expansion is very possible within a year or two of it becoming operational. They present the following additional information about North Baja shippers:
 - Most North Baja shippers are generators, making huge investments in power plants. PG&E NEG expects these generators to have long-term gas supply and transportation arrangements.
 - The staff report correctly points out that North Baja shippers may acquire firm capacity as part of El Paso's ongoing open season process to expand its pipeline.
 - North Baja shippers may acquire capacity from existing El Paso capacity holders, or buy gas at Ehrenberg.
 - PG&E NEG holds firm El Paso capacity that can be used to serve the Otay Mesa Power Project.
 - The staff report (p.72) discusses the bi-directional lateral project from Daggett to Ehrenberg. PG&E NEG says this is another potential source for gas supply for North Baja shippers.
- PG&E NEG notes that on page 74, the report states that the Energy Commission should investigate whether the North Baja project would force curtailments under conditions as experienced in the summer of 2000, and other plausible scenarios. PG&E NEG is concerned that this doesn't take into account several market factors: 1) North Baja service to Rosarito will alleviate capacity concerns in the San Diego area; 2) North Baja shippers

- may place a higher value on El Paso capacity than Southern California does; 3) Generation in Arizona (8,000 MW in advanced development or construction) will likely be served by El Paso and could be far greater than North Baja requirements; and 4) The amount of expansion of the El Paso and Sonoran Pipelines could also affect gas supply flows into California.
- PG&E NEG provided comments on p. 66 of the staff report on upstream demand on GTN. PG&E NEG agrees that upstream markets use capacity that was used in the past for deliveries to PG&E when not all of the firm capacity to California was being used. This has resulted in a mismatch at Malin, much of which will be alleviated with GTN expansions in 2002 and 2003. PG&E NEG notes that it is best to let the market make these determinations.
- PG&E NEG provided comments on p. 66-67 of the staff report on Canadian gas supply and Alliance pipeline. The report states that western Canada may become a less reliable source of natural gas for California. PG&E NEG makes the following points:
 - Canadian gas is and will continue to be a reliable source for California. Production in Canada continues to increase. Active drilling rigs in Canada are 56% higher this April compared to last April, and gas well completions from Jan-Apr 2001 were 29% greater than Jan-Apr 2000.
 - The development and construction of pipelines to transport gas from Northern Canada and the Arctic regions is likely this decade and California will be an attractive market for these supplies.
 - Since the Alliance Pipeline went into service, GTN's deliveries have increased. It appears that Alliance's real competition is with the TransCanada Pipeline as their deliveries have decreased.
 - California has to compete with other markets in all supply basins including the Rocky Mountain basins and San Juan basin. PG&E NEG maintains that the market will determine the flows from each of the supply basins serving California.
- PG&E NEG notes that the concept of slack capacity may have some appeal, but it is somewhat inconsistent with firm capacity rights. They also note that interstate capacity will only be built to California if shippers have contracted for it.

Calpine Corp.

- Calpine has long-term commitments to provide reliable power to the State of California. Long-term reliable power requires reliable gas supplies.
 The existing pipeline infrastructure is not sufficient for Calpine's needs.
- Calpine is seeking long-term firm capacity arrangements that currently do not exist in either the SoCal Gas and the SDG&E systems.
- Calpine believes there is insufficient intrastate pipeline capacity to promote gas-on-gas competition and to move gas from south to north.
- Calpine notes historic regulatory regimes that have hindered new pipelines, especially interstate pipelines coming into California.

Wild Goose Storage Facility

- Wild Goose commented that the Energy Commission has done an excellent job of capturing the state of the gas infrastructure in California. The gas demand in California is highly volatile, very weather sensitive and generation demand is the driver of that volatility.
- They characterize the problem as a peak problem, especially when you consider that average demands do not cause the existing pipelines to be completely utilized at all times of the year. For that reason, storage can be a very efficient solution for solving peak period reliability concerns.
- Wild Goose says that making sure that the backbone transmission system is upgraded sufficiently so that it can take gas that is delivered out of storage is very important. The modest costs of upgrades to accept gas that can come out of their storage system is quickly paid for because it produces significant benefits for the system as a whole.
- There should be a slack capacity factor on pipelines for storage capacity as well as for transmission needs.
- Wild Goose believes that utilities should have both the incentive and the obligation to maintain their backbone system to accept withdrawal capacity of independent storage facilities. They should be able to take the deliverability from independent storage with an equal priority to the withdrawal they take from their own storage (as required by existing CPUC decisions). Also, there should not be any discriminatory tolls that impose higher costs on customers of independent storage facilities. The quid pro quo for that is that any expansion or upgrades of transmission to accommodate storage should be assured recovery in rolled-in rates.
- Wild Goose supports the encouragement of a secondary storage market where customers can trade their capacity such as what Wild Goose supported in the comprehensive settlement proposed in Southern California (currently pending before the CPUC).

California Cogeneration Coalition (CGC)

- CGC strongly supports the direction that staff is taking and agrees with staff's conclusions that we need to add natural gas infrastructure capacity, including enough to have a slack capacity factor.
- CGC agrees with staff, as well as evidence presented in the CPUC proceedings, that there is a problem with bottlenecks on the intrastate pipeline system at the point of takeaway at the California border. CGC believes that bottlenecks impact prices as demonstrated by prices into SoCal versus prices at the San Juan basin.
- Back in 1990, the CPUC adopted a standard that there should be 15 to 20% slack capacity factor above cold year forecasts. CGC notes this was done at the Energy Commission's urging.
- CGC agrees that it is difficult to determine exactly what the slack capacity standard should be, but it should at least take into account both cold year and dry hydro conditions. Forecasts used to determine slack capacity

- must also take into consideration electricity transmission constraints and local transmission requirements.
- CGC believes that if you build the system to include slack capacity, all
 consumers benefit. They maintain that, in just one day during very
 substantial spikes in natural gas prices, you can cover the cost of capacity
 expansions such as what SoCal Gas is talking about installing.
- CGC supports expansions that SoCal Gas is now considering; however, they do not believe these expansions will be enough. They support additional capacity expansions to bring natural gas from the Mojave, Kern River, and the Sonoran pipelines into the SoCal Gas system. CGC also believes additional capacity from delivery points such as Wheeler Ridge, Adelanto and Hector Road should be considered.
- CGC believes that a possible expansion at Topock, that would be more expensive, should at least be considered by SoCal Gas.
- CGC believes that there are negative incentives at the CPUC that preclude or forestall prompt expansion of capacity. They note that the PBR mechanism for SoCal Gas delays rate recovery. They state that the SoCal Gas cost incentive mechanisms, that allow for profit sharing with core ratepayers, create a disincentive to adding capacity. They also note that the SoCal Gas risk sharing mechanism may be a contributing factor.

NATURAL GAS STORAGE ISSUES

FERC

FERC notes that clarification of storage matters in the staff report would be valuable. These include available noncore storage services, the rights and obligations of non-core customers, whether firm redelivery services are available, how the noncore storage operations are integrated into LDC delivery capacity, and how rebundling of storage might be accomplished.

Duke Energy

- Duke is unalterably opposed to rebundling of storage. They note that all storage capacity in Southern California, excess to core requirements, is fully contracted for at this time.
- Duke supports continued reliance on bilateral storage arrangements between electric generators and storage providers.
- Rebundling would undermine the viability of existing and expanded private storage fields in California.

PG&E Company

 PG&E suggests the proposed recommendation in the report to rebundle storage should be reconsidered. Problems with lack of noncore storage arose in a period when most electricity was purchased on spot market. The move to long-term electricity contracts will encourage more

- generators to utilize storage to minimize risks of running out of gas and having to meet their contracts with expensive spot purchases.
- Rebundling may not be compatible with the gas market structure that is based on separation of core and noncore markets. This also raises practical and legal questions since the CPUC cannot order generators to store gas.
- PG&E suggests that the ISO and end-use customers could consider offering contracts to generators that allow them to recover storage costs.
- Also, gas-fired generators could be required to maintain back-up or alternate fuel capability, although PG&E points out that this issue would be under FERC jurisdiction.

Sempra Energy

- Sempra disagrees with the staff report's recommendation regarding the need for additional storage. They maintain that it seems baseless since customers have not been using the storage available to them.
- Sempra disputes the staff implication in the report that storage fields were stressed.

Calpine Corp.

- Calpine is a proponent of storage. They have announced a 10-year deal with Lodi Gas storage. They are also in the business of developing storage on a proprietary basis.
- Calpine doesn't support rebundling of utility storage. They believe generators have opportunities to go into the market and acquire storage and use it. Their concern is that rebundling may present a disadvantage to the development of additional third-party storage in the state.
- Calpine strongly supports infrastructure development and noncore incentives to get risk capital into the state. Storage should be encouraged, whether it is utility or private.

Wild Goose Storage Facility

- Wild Goose is the first independent storage facility in the State. As a result of an open season last winter, the Wild Goose facility is completely subscribed to its existing level of capacity for the next four to five years.
- Wild Goose announced another open season for expansion of the project and received extremely strong support for all of the expansion that they put out for open seasons.
- Wild Goose believes there are numerous benefits of storage that should be considered. Storage is more reliable because it requires less building of pipe to get that gas to customers. An upstream market such as the Northwestern and Midwestern clients who would buy gas away from the California border can't divert storage. The regulation of storage facilities like Wild Goose is within California's jurisdiction.
- Use of storage can improve the transmission load factors on the utility pipelines, moving gas at off-peak periods so that we can inject gas.

- Overall it increases the load factor on the utility pipeline so that all customers see reduction in their transmission totals when those increased load factors are rolled into CPUC rates.
- Storage customers can also put their gas into the market in periods of peak pricing, selling into those peaks and dampening prices. When we can generate maximum withdrawal into those markets, it can have a very significant impact on reducing prices, which flows through to all customers. For example, a 30 percent dampening of prices for just one month can save PG&E's noncore market \$10 million.
- Independent storage can help to reduce curtailments and diversion for the core, which benefits all customers, not just Wild Goose customers or customers of any other independent.
- Independent storage also provides other efficiencies because it does not add to the utility's ratebase. When Wild Goose was certified, the investment was made entirely at their risk. They have no captive customers or service territory and have to successfully compete to sell their services or they don't pay off their investments.
- Independent storage also promotes beneficial competition because utilities will have to compete in order to sell their storage services to the noncore market, and hopefully to the core market since they believe they can provide low cost efficient storage to core customers as well.
- Wild Goose strongly supports staff's recommendation to encourage independent storage. They recommend against rebundling of utility storage and suggest this be deleted from the report.
- To encourage storage we should be moving toward fully unbundled utility storage, which has not yet been completely done. Utilities should be at risk for any uncommitted or uncontracted for storage and these costs should not be placed in the transmission rates of all customers.
- Customers should be allowed the opportunity to either purchase utility storage or not, so that they have options in trying to find the right package of storage services to meet their particular needs.
- Bundled storage involves too many cross-subsidies. Customers who have expensive storage profiles (injecting a lot of gas in and out) are swinging on the balancing flexibility built into the system. There are very generous balancing allowances on both California local distribution companies. Those customers are getting storage cheaper than it would actually cost them if they had to go out and get the service themselves. Customers with relatively flat load who don't place many demands on the system are subsidizing those other customers.
- If storage is unbundled, customers go out and acquire the storage they need for their particular use and are charged correspondingly. This sends the correct price signal to the utilities in terms of managing their own storage.
- Wild Goose believes that the proposal to rebundle was generated by concerns about what generators and noncore customers did last summer when it appeared they did not fully utilize storage that was available to

- them. This caused less stored gas to be bid into the market when there were price spikes later in the year.
- Their analysis of data found that at the time customers would have been still injecting for winter storage (the normal storage injection cycle) they were faced with futures market prices that indicated that the summer prices would be much higher, or significantly higher, than winter prices. Wild Goose notes this was a very unusual situation.
- Many noncore customers essentially optimized their resources by selling gas for the higher prices in summer, since they could buy it back less expensively in winter. What happened was that futures prices didn't pan out and were higher in winter, so customers were not able to buy supplies back more cheaply.
- The losses incurred last winter have had a significant impact on the market and customers are not repeating the mistake this year or in the future. Today you have a high price for gas this summer due to summer electric generation. At the same time futures prices for the winter are about the same, or a little lower. This situation could tempt customers to repeat what they did last year. Instead, customers are injecting gas into storage to provide for their winter needs.
- Wild Goose believes this is a good indication that the State does not need to rebundle storage in order to assure that it will work the way it is supposed to.
- Generators are making significant investments in storage assets by taking capacity in open seasons and signing up for new pipeline capacity. They are investing in infrastructure, which is exactly what you would want them to do to provide for their own needs.
- To encourage independent storage, the State could reduce the time for approving projects by eliminating the need to go through two duplicative proceedings to get eminent domain. While Wild Goose works for more acceptable arrangements with landowners, it is almost impossible to build a pipeline in California without using eminent domain. California should eliminate the second unnecessary eminent domain hearing.
- Expansion of storage should not be subject to additional CPCN requirements that would require additional hearings. Their investments are at their own risk, not ratepayers.
- One way to encourage people to use storage properly is to change the balancing requirements that are extremely generous but that promote cross-subsidies. There is no disincentive for customers to stress the system, neither is there any incentive for customers to go out and contract for storage. Reducing the flexibility in the balancing rules would send the right signals to encourage customers to use storage.

California Generation Coalition (CGC)

 CGC does not support rebundling of storage. They also do not advocate further unbundling of natural gas services, as some parties are suggesting.

ELECTRICITY & STORAGE ANALYSIS

Sempra Energy

- Sempra notes that the report appears to suggest that SoCal Gas will have a problem making it through the year without curtailments. They say a more accurate portrayal is that SoCal has not curtailed any customers in excess of 10 years and is confident it will have enough gas in storage to serve customer needs this winter.
- Sempra notes that current storage levels are at 50 Bcf and that they are well on their way to meeting the winter core storage target. They will also be able to meet summer electric generator demand, although the system will be close to full, which underscores the importance of their proposals to sell cushion gas from storage fields to augment supplies.
- Sempra disagrees with staff's portrayal of the situation in SDG&E (that it would likely have to curtail service to some customers). Sempra argues there is no clear basis for this assumption or discussion of whether there are any externalities that could ameliorate any proposed curtailment. Sempra says it is not clear whether this assertion is based on the belief that SoCal would have to curtail, or if the SDG&E curtailment would result from load restrictions totally within the SDG&E service territory.
- Sempra notes the need for corrections to accurately reflect conditions on SDG&E system on p. 78 and the reference to "supply shortage". They note that SDG&E is a pack and draft system designed to serve hourly loads that exceed hourly capacity. Sempra believes that the current write-up could be interpreted as suggesting that SDG&E needs to add capacity of 12 MMcfd to eliminate shortages.

PG&E Company

PG&E supports analyzing the gas and electricity market to prepare California for the regulatory and infrastructure decisions that lay ahead. However, PG&E maintains that analysis into whether summer withdrawals from storage for electric generators will the threaten utilities' ability to meet storage targets for winter is duplicative of utility activities in this area.

PLANNING & DESIGN CRITERIA

Duke Energy

- Duke suggests the establishment of a firm reliability standard of 1-in-10 years, with utilities authorized to pursue projects consistent with this standard, and with assurance of rate recovery on a traditional basis.
- Duke says this requires fundamental changes in the way reliability planning is conducted. Duke suggests considering the complete supply chain from wellhead to burner-tip, including impacts of upstream demand.
- Duke also points out the need for coordination with FERC on interstate pipelines and potential bottlenecks in backbone take-away pipelines.

- Duke recommends a coordinated investigation conducted under the AB
 970 model related to electric transmission and generation.
- Duke recommends adoption of additional planning criteria based on adverse hydro conditions along with 1-in-35 year standard for core customers. Duke notes that electric reliability planning has always been done based on adverse hydro because, while the combination of extremely low hydro conditions in California and the Pacific Northwest has an extremely low probability of occurring, it has extreme negative consequences. Natural gas reliability planning should move to this basis.

PG&E Company

- PG&E shares staffs' view of the increasingly close interaction between gas and electricity markets.
- PG&E notes that the report did not adequately address the uncertainty in power plant gas demand. The report was focused on the short term, but PG&E believes there is much more uncertainty in electricity demand beyond 2002. The report implicitly assumes growth in power plant demand, but in some scenarios it could be below current levels due to increases in power plant efficiency and weather related hydro conditions.
- PG&E states that regulatory guidelines and planning criteria should be revised to explicitly recognize lack of back-up fuel by noncore users. Revisions could include using a dry year scenario reflecting increased electric demand similar to current hydro conditions.
- PG&E suggest establishing a clear reliability planning standard for noncore such as 1-in-10 year probability of gas diversion to core customers, or negotiated value-of-service standard.
- PG&E suggests that the core should be required to hold contracts for gas transportation and storage to satisfy 1-day-in-10-year cold event to reduce reliance on diversions from noncore.

Calpine Corp.

- Calpine states that interstate pipeline design criteria should take into consideration not only winter, but summer peak conditions as well.
- They note that the staff report suggests a regulatory approach to encourage or mandate slack capacity. Calpine's concern is that mandating slack capacity principally on the utility side would ignore cost causation principles and will not encourage alternative pipelines to come into the state.
- Slack capacity should include both intrastate and interstate pipeline capacity. But, Calpine believes the market should decide what the appropriate level of slack capacity should be.
- Calpine acknowledges the recent open seasons for intrastate capacity by PG&E, but notes that the rules must allow them the ability to get the necessary levels of service. Current open season rules will not allow Calpine to meet it gas supply needs.

 Calpine notes that expanded interstate pipeline capacity, whether it comes to the border or into the state, will help to alleviate some of the problems caused by upstream demand.

CURTAILMENT RULES

FERC

- FERC notes that the discussion in the report of the dependency on interruptible load is well developed but called for clarification of what options are available to shippers to avoid interruption. FERC posed three example questions: Can a core shipper avoid interruption by purchasing storage service? Can noncore customers elect firm service? Can noncore shippers firm up their service by supporting a capacity expansion project?
- FERC notes that because electric generators do not have fuel back-up the pro-rata gas curtailment rules designed to protect core customers could actually do them harm given the fact that most core customers need electricity to run their furnaces and air conditioners. FERC suggests the report could recommend solving this problem by replacing end-use priority schemes for transmission capacity with a firm/interruptible priority scheme

Sempra Energy

- Sempra states that the proposed policy in the report to curtail the least efficient electric generators first would not necessarily lead to greater electric reliability. They assert a better policy is curtailing generators on an equal basis under the current pro rata method. They maintain the current method is also fairer.
- Sempra believes the efficiency proposal begs the question of how to determine efficiency by raising the example of high heat rate for combustion turbines as a difficulty in determining who should be curtailed and who is more efficient.
- Sempra maintains that the discussion of curtailment rules in the report is not accurate in stating that they were originally established for cold weather. Sempra says that although planning criteria uses cold weather condition because these conditions lead to the highest total load, the rules were set for any time of year. The largest change since enactment of these rules is the elimination of back-up fuel capability.

Duke Energy

 Duke believes that expansion and upgrading of the gas transportation system is far preferable to fine-tuning the curtailment and diversion rules in anticipation of more frequent curtailments.

IN-STATE NATURAL GAS PRODUCTION

California Independent Petroleum Association (CIPA)

- CIPA supports the Energy Commission's recognition of the potential and benefits of increasing in-state production. They support efforts to identify dysfunctions in current regulatory and utility policies regarding interstate and intrastate pipeline infrastructure, capacity constraints and delivery to end-users.
- CIPA agrees with proposed mechanism to monitor state drilling activity and production levels to determine if production is keeping pace with demand. Information should be shared with local, state and federal policy makers as an early warning system.
- CIPA agrees that barriers to in-state gas production should be identified and that the CPUC and the Energy Commission should recommend actions to increase in-state supplies. They recommend that the Energy Commission work with CIPA, SoCal Gas, and CARB on air quality issues.
- CIPA notes that California production has historically accounted for as much as 25 percent of total gas use and now has declined to 15 percent. California in-state production can be increased to come closer to this historic level with regulatory relief and proper incentives.
- CIPA maintains that the downward trend in in-state production was due to environmental laws, high drilling costs, low gas prices in 1990's and labor shortages. Many producers believe that operational policies and statutes governing state's major gas utilities have also contributed to production declines.
- CIPA notes that existing law provides almost exclusive authority in setting terms and conditions for pipeline connections for new natural gas wells to utilities and that they have used this authority to stifle in-state production in favor of out-of-state supplies.
- CIPA points out the difference between wet and dry gas and the need to look at incentives to encourage both.
- CIPA notes that there have been historic delays of six months in receiving approval to interconnect new wells. They also note that the overly burdensome and expensive terms and conditions for new interconnections have led producers to abandon new exploratory projects.
- CIPA proposes the following reforms to increase in-state production:
 - Strengthen the California Natural Gas Policy Act by establishing mandatory timeframes for interconnections and new incentives for utilities to accept in-state gas.
 - Create an oversight process to enforce rules and regulations for hook-up.
 - Encourage new exploration by requiring utilities to install metering sites or allowing producers to install them.

- Allow producers to bear the costs of interconnection such as pipeline construction and labor costs if the utility workforce is overburdened.
- Require utilities to allow in-state production to flow to alternate markets.
- Require utilities to sell off gathering systems consistent with AB 1890 and the Gas Accord.
- Prohibit utilities from assessing local transportation charges on gas moved from storage (where the utility has already been paid to move gas).
- Create incentives for development and permitting of blending facilities.
- Create tax credits for in-state gas used to produce electricity in California.
- Allow producers access to fee property, easements and right-of ways to tie-in to utility pipelines.
- Authorize utilities to exercise eminent domain to accommodate interconnection.
- Standardize city and county permitting for gas wells, pipelines and interconnections.
- o Eliminate the 50 Mcf rule that currently constrains production.
- Allow producers the flexibility to deliver gas to alternate markets when pipelines are shut-in or curtailed.
- Create new tax and financial incentives for landowners to provide right-of-way and easements.
- Energy Commission/CPUC evaluation of pipeline capacity adequacy for new in-state gas production at East Lost Hills, Lathrop, San Joaquin Valley, Rio Linda and Grimes fields.
- Support legislative initiatives: AB 1234, AB 1350, AB 14xx, AB 1233, and AB 23xx.

PG&E Company

- PG&E notes that California producers already enjoy an advantage over out-of-state producers in that they don't pay interstate transportation costs that give out-of-state suppliers a lower netback price for gas.
- PG&E maintains that a fundamental problem not mentioned by staff is the low Btu content and large amounts of non-burnable contaminants in California produced gas. Some equipment designed for conventional gas will not properly function on low-quality gas and cannot safely be accepted into the PG&E system.
- PG&E suggests incentives for end-use customers to connect directly to producers of low Btu gas separate from the PG&E system that are being pursued in current legislation. PG&E suggests another possibility is tax or other incentives to producers to upgrade the Btu content of in-state gas.
- PG&E states that, contrary to the staff implication in the report, PG&E is already providing rapid and efficient service for in-state producers. Most

interconnections occur within 45 days; on average 39 days. PG&E notes that Btu content and land easement and permitting issues can cause delays. PG&E is also working with producers on the sale or auction of its traditional gas gathering system to enhance in-state production.

Calpine Corp.

- Calpine notes that, currently, California production of natural gas is not being maximized. In Calpine's estimation there is limited access to gas transmission and delays in getting production on-line.
- They note limitations on the ability to deliver low Btu gas to the system. Calpine points out that there are apparent economic penalties for attempting to blend gas or move it to other markets where it would be more profitable.
- They reiterate CIPA's concern about the shut-in of profitable wells due to PG&E's 50 Mcfd rule.
- Calpine notes that they could increase their own in-state production primarily in the Rio Vista Gas Field, but in order to do so, they would need to acquire PG&E's gathering system. Calpine states that although they have been in negotiations with PG&E for two years, they have been unable to conclude a sale.

Solar Development Cooperative (SDC)

- SDC comments that the real culprit leading to the unnecessary crisis effecting millions of consumers is the market power of the fossil fuel industry.
- SDC wants to assure that these industries are not provided any further incentive or advantage by the State of California to increase reliance on fossil fuels.
- SDC believes a fundamental question is not how, but whether to provide gas pipeline deployment. They contend that the fossil fuel "cartel" should be fully prosecuted for abuses they allege against consumers.
- SDC maintains that the State of California is suppressing needed renewable energy technologies that would provide autonomous independence from market power abuse.
- SDC urges the Energy Commission to assure competitive manufacturing opportunities and rapidly increased production of building-integrated photovoltaics and fuel cell products. SDC believes these efforts will take significantly less money and time than natural gas pipelines.

PARTIES COMMENTS ON ELECTRICITY & NATURAL GAS COMMITTEE'S DRAFT FINAL REPORT ON NATURAL GAS INFRASTRUCTURE ISSUES

California Public Utilities Commission (CPUC)

- The CPUC commented that the draft report does not provide an adequate explanation for the price spikes in California border priced-gas over the last year. They comment that the report does not acknowledge the CPUC's complaint of market manipulation at FERC against El Paso Natural Gas.
- The CPUC disagrees with certain conclusions about the intrastate natural gas capacity serving California.
- The CPUC notes that the report should acknowledge California's numerous accomplishments to meet our future natural gas capacity needs and add flexibility for California's gas consumers.

SEMPRA Comments

- 1. Intrastate Pipeline Capacity: Sempra commented that the Energy Commission should change the report text to eliminate the implication that there is a more significant intrastate transmission constraint in Southern California relative to Northern California.
 - Sempra contends that the report provides no evidence to support its conclusion that the Southern California system has been more constrained that Northern California. Between September 2000 May 2001 PG&E's utilization of firm capacity of 3143 MC has been 94%, while SoCal Gas' utilization of its firm 3,500 has been 97% -- hardly a significant difference. SoCal's rate was slightly higher due to storage injection.
 - Sempra states that the report does not acknowledge that unlike PG&E, SoCal Gas is adding 375 MMcfd of capacity to its backbone system by the end of this year.
 - Sempra notes that the report does not acknowledge that unlike PG&E's system, few, if any, new gas-fired power plants are being sited directly on SoCal Gas' transmission system.
- 2. Natural Gas Storage: Sempra requests that the Energy Commission's conclusion that "SoCal Gas will likely be able to satisfy the peak demand of electric generators the summer of 2001 and still store enough gas to serve core needs at peak during the winter of 2001-2002" should be revised to state that "SoCal Gas is fully able to meet its summer and winter demand."
 - Sempra notes that August 13, 2001 storage inventories for SoCal Gas were 85.1 – there has only been one year with a higher storage inventory level at this time of year since storage was unbundled in 1994. Sempra

- points out that the report ignores the fact that SoCal Gas has made it though winters with as little as 60 Bcf going into the winter season.
- Sempra indicates that even if the High Gas Use case in Figure 6-7 materializes So Cal Gas is still in good shape going into this winter.
- Sempra notes that the report should acknowledge that SoCal Gas received approval from CPUC to sell 23 Bcf of cushion gas from Montebello of which 10 Bcf will be produced before the end of winter.
- Sempra believes the report should acknowledge that SoCal received approval to make 14 Bcf of cushion gas available from Aliso Canyon and Goleta storage fields.)
- 3. Natural Gas Prices: Sempra commented that there is no evidence to support the dramatic conclusion of the report that "an inadequate natural gas infrastructure that limits the ability of California to receive gas has been a major contributor to high prices for gas in California." Sempra states that the Report should be revised to eliminate repeated implications that poor utility planning made a major contribution to recent price spikes. In addition, Sempra notes that the report should also reflect that recent increase in gas demand by electric generators was "entirely unforeseeable".
 - Sempra argues that the casual observation that high prices occurred at the same time as the utilities utilization rates were high does not constitute evidence of causation. If intrastate capacity was less than what a competitive interstate market could supply, it would tend to lower prices because of competition among pipeline suppliers.
 - Sempra notes that the report ignores other contributing factors for winter price spikes such as El Paso's pipeline rupture, runaway wholesale electricity prices, 1-in-75 year drought, colder than normal winter, low levels of noncore storage, extremely high utilization rates for all incoming interstate pipelines.
 - Sempra contends that the report's explanation for why gas prices have dropped is equally non-analytical. The report fails to consider the following
 - SoCal Gas utilization rates in June/July averaged 96.5% when prices moderated, about the same as seen during the highpriced period of September through May.
 - No CPUC decisions approving additional pipeline capacity during the same period (even when SoCal announced capacity additions the price didn't immediately drop)
 - Until FERC caps, generators were willing to pay any price for natural gas.
- **4. Improving Intrastate Pipeline Systems:** Sempra contends that the report contains repeated implications that utilities do a poor job of planning their intrastate system. Sempra believes that the report should be revised to recognize that the demand forecasting challenge posed by noncore customers

(i.e. the unpredictability of knowing what level of demand electric generators are planning their systems for and what amount of capacity these customers are willing to pay for) is best solved by requiring electric generators to sign up for long-term firm commitments for specific quantities. They contend that long-term commitments solve the capacity-planning problem.

- The report states: "The Energy Commission and the CPUC should investigate whether proper incentives exist to support utility investments in intrastate gas systems and make necessary regulatory changes to eliminate any disincentives that may exist" Sempra sites this as a example of repeated implications in the report that utilities do a poor job of planning. They maintain that this statement is wrong. Under the current regulatory environment SoCal is expanding its system by 375 MMcfd and PG&E is planning to expand by 200 MMcfd without any help or prodding from the Energy Commission.
- Sempra appreciates the Energy Commission's efforts to help establish a guideline or slack capacity. SoCal has long advocate the 15-20% slack factor.
- Sempra cautions that the report fails to provide a complete picture because is doesn't recognize the existence of slack capacity until the dramatic demand increase in summer of 2000. The report does not recognize the Energy Commission's role in establishing this criteria at the CPUC over a decade ago. If the report is alluding to the fact that this criterion is insufficient, the report should recommend the Energy Commission re-evaluate its recommendation to the CPUC rather than criticizing the utilities.
- Sempra suggests that the report needs clarification on the demand assumptions for the 15-20% slack factor. The report may be suggesting that the slack be based on a one in 10 year hydro condition rather than average temperature condition, which may be appropriate. However, there is no evidence to support that it is.
- Sempra states that the report fails to recognize that establishing a 15-20 slack factor based on an average year still provides 10 percent slack factor in a 1-in-10 dry hydro year. One of CPUC assumptions was that establishing the criteria relative to a normal year leaves sufficient capacity on the system to deal with unusual years.
- Sempra contends that in focussing on criteria, the Energy Commission has overlooked the most important challenge facing utilities in planning their systems which is noncore demand. Electric generators have many choices: to locate on the utility system or an interstate system; to dispatch or not under unpredictable electricity market; to bypass or not bypass; to sign up for interruptible or firm service. SoCal believes that the recent problems with forecasting noncore customer demand can be avoided if utility infrastructure planning is based on noncore customer contractual commitments.

- **5. Curtailment Policy:** Sempra comments that the report should be amended to adopt the CPUC's decision on curtailment. They assert that the CPUC just did an "exhaustive" OII in SDG&E curtailment rules and found that generators should be curtailed on pro-rata basis. Sempra concurs with the CPUC that this is more appropriate than the one suggested by the Energy Commission.
- 6. Optimizing Noncore Use of Natural Gas Storage: Sempra suggest that the report should be revised to reflect the impact of tighter utility balancing rules on storage incentives. Sempra agrees with the CEC on need for tighter balancing rules because customers now use storage without having to pay for it. But, they note that this action by itself will not increase storage going into the winter because the incentive to store is based on the cost of storing and withdrawing versus customers forecast of the cost and reliability of flowing supply over the winter period.
- **7. Peak Hour Demand Analysis for Utilities:** Sempra comments that Table B-4 in the report should be revised to account for pack and draft capabilities of SoCal Gas and PG&E that are currently ignored in the report.
- **8. General Comments:** Sempra contends that the report relies on the situation in 2000/2001 to support the need to build more infrastructure, but fails to recognize the unusual nature of this time period: 1-in-75 year drought; high baseload outages; and tight reserve margins. The report should acknowledge that gas-fired generation in the SoCal gas system would significantly decline from 2000/2001 levels as average heat rates in the WSCC dorp to accommodate displacement of less efficient generators by new planned generation.
- **9. In State Gas Production:** Sempra wants to point out the unique gas quality issues that affect Southern California as well. In Southern California some of the instate production has higher Btu values that may not make the gas suitable for use in natural gas vehicles regulated by CARB. These requirements will likely require producers to perform additional processing on their gas streams delivered to the utility system.

Southern California Edison (SCE) Comments

Contribution of the Exercise of Market Power to High Gas Prices: SCE recommends that the Final Report be issued after modifying all references to recent gas price increases in which such increases are attributed primarily to inadequate gas infrastructure or lack of slack capacity.

SCE notes that the conclusion in the report regarding the reasons for the extraordinary gas price run up during the last year was the lack of slack pipeline capacity. Although the report acknowledges that there may have been an exercise of market power that contributed to these price increases, the discussion lays most of the blame on "inadequate gas infrastructure."

- SCE contends that this conclusion is at odds with the CPUC complaint currently pending before the FERC (RP00-241-000) that alleges market power abuse has been the primary driver in recent gas price increases. SCE has actively supported the CPUC complaint and has introduced evidence to substantiate this allegation.
- SCE argues that the report's apparent conclusion that the primary driver of increased gas prices was inadequate infrastructure, rather than the exercise of market power, could undermine the State's goal to protect California consumers from price gouging.

The Utility Reform Network (TURN) Comments

- 1. The Relationship between Inadequate Slack Capacity and Gas Price Spikes: TURN suggests that one of the fundamental conclusion throughout the report that price spikes this last winter resulted from inadequate slack capacity has no factual support, ignores actual market dynamics, and is based on a persistent confusion of the effects of interstate versus intrastate capacity on commodity prices.
 - TURN argues that a slack capacity factor on the upstream interstate system, if it results from pipelines accessing different gas producing basins, can result in competition between sellers trying to sell gas into California; this is gas-on-gas competition. Even the existence of interstate slack capacity does not guarantee price benefits if a limited number of capacity holder on the upstream system can exercise market power, as occurred last winter.
 - TURN contends that slack capacity on the intrastate system does not increase competition or lower prices, as long as there are no actual constraints on the system.
 - TURN asserts that there is general agreement that lack of injection into storage during last summer was not caused by high intrastate pipeline utilization but by forward price curves showing lower prices in the winter. If receipt point capacity exceeded incoming capacity there would be no greater operational flexibility but rather just stranded intrastate capacity.
 - TURN notes that there were no curtailments on the PG&E and SoCal Gas systems this past winter. While the SoCal Gas system was running at full capacity for at least months during the winter, and price spikes occurred during two of those months, several other factors, including possible market manipulation and market power as well as record low storage levels, may have contributed to price volatility.
 - TURN comments that while the report properly notes that we need new planning and design criteria to address the problem of electric reliability in the new era of no dual fuel capability, the report does not distinguish between the need for capacity for noncore reliability versus capacity for reducing price volatility.
 - TURN suggests that there may be good reason to consider new planning criteria based on both temperature and hydro conditions, to assure reliable

- gas service for electric generators. However, they contend that there is no basis to throw in an additional 15-20 percent slack factor on the assumption that it will lower commodity prices, given that it is unclear who will pay for slack capacity.
- TURN is concerned that the state may embark on a major building program only to burden residential and commercial gas customers if the electric generators who are demanding the construction of capacity will not pay their freight through bypass of intrastate capacity, rate design games to assign disproportionate amounts of the new costs to existing residential and commercial customers or both.
- TURN agrees that some additional capacity may be beneficial for noncore reliability and Turn supports the 375 MMcfd of backbone expansion on the SoCal Gas system. TURN believes it is premature and prejudicial to conclude that major capacity expansions will provide net benefits due to commodity price reductions.
- **2. Noncore Storage:** TURN is troubled that the report encourages greater integrated system planning but at the same time withdraws the initial recommendation to consider rebundling of storage.

TURN suggests that there is no sense in doing integrated planning if more efficient use of storage through rebundling is not examined as a possibility. As long as electric generators can choose whether or not to store gas, they, together with upstream interstate pipelines can repeat the same market manipulation with the same detrimental effects on California economy that occurred last winter. As least as long as capacity is somewhat tight, storage rebundling can prevent market manipulation.

PG&E Comments

- 1. Natural Gas Prices: PG&E commented that they believe that the report places unfair blame on California's infrastructure as a primary cause for high prices. PG&E strongly believes that the evidence uncovered during FERC hearings shows that the unavailable capacity on the El Paso system was a major underlying reason for the gas price increases.
 - PG&E contends that, as demonstrated at recent FERC hearings, PG&E's line 300, which connects with Kern River, Transwestern and El Paso, had an average utilization rate of only 73 percent from March 1, 2000 through May 31, 2001, and was seldom full. This is the period El Paso Merchant Energy held the contract capacity on the El Paso Natural Gas pipeline that is at the center of the dispute. PG&E states that take-away capacity at the Southern California border was not a problem for PG&E.
 - PG&E notes that information has come to light during the FERC hearings that indicates that beginning in July 2000, the El Paso Natural Gas pipeline lost the ability to deliver almost 500 MMcf/d to the Topock delivery point due to a variety of reasons. PG&E believes that the unavailable

capacity on the El Paso system was one of the real culprits behind California's high gas prices.

- 2. In-State Gas Production: PG&E commented that they are disappointed that earlier comments regarding in-state production were not considered
 - PG&E commented that the tone of the report is one-sided, reflecting producer views with no balancing view from the utility side.
 - PG&E asserts that they have been working with California producers to get new wells connected expeditiously, with average well connection time now 38 days, which has resulted in 3-4 times as many wells being brought on-line compared to two years ago.
 - PG&E also commented that the low Btu content of most gas produced in California is a legitimate issue. Where feasible, low btu gas will be accepted; however, there is an obligation to deliver certain quality gas at the burner tip. Accepting too much low btu gas can affect the ability to deliver the accepted quality gas.
 - PG&E also commented that several attempts have been made to complete a deal with no success, although not from lack of trying.
- **3. General Comments:** PG&E supports the proposed changes to the Executive Summary being filed by Sempra Energy.

Independent Energy Producers Association (IEP) Comments

- 1. General Comments: IEP notes that it has not previously found it necessary to submit comments. However, because Sempra's letter to the California Energy Commission includes recommendations with implications that extend well beyond the narrow discussion in the letter, IEP is now providing comments.
 - Specifically, IEP is concerned about Sempra's recommendation that electric generation ("EG") customers who use Sempra's gas transportation system should be required to enter into long-term firm commitments for specific quantities of transportation capacity.
 - Many of IEP's members rely on natural gas for merchant generation plants, to fuel cogeneration facilities, or to supplement renewable primary fuels such as biomass, solar energy, or landfill gas. Thus IEP's members are a substantial portion of the EG customers that are directly affected by Sempra's recommendation.
 - IEP notes, by way of background, that the tariffs of the Sempra gas
 utilities (Southern California Gas Company and San Diego Gas & Electric
 Company) currently require only a two-year commitment for firm
 transportation service. In proceedings before the CPUC, Sempra has
 stated that it believes an appropriate long-term commitment by its EG
 customers would extend for 15 years and include substantial take-or-pay
 requirements.

- IEP commented that Sempra's recommendation to require long-term commitments from electric generators has several disturbing implications.
 - A. The recommendation is profoundly anti-competitive. IEP comments that Sempra's recommendation, if adopted, would lock up the bulk of the California gas transportation market for 15 years, effectively killing the prospect of any competition for intrastate gas transportation. IEP expects that Sempra's utilities would continue to maintain a dominant share of the electric generator market even if they were forced to compete for customers on the basis of terms and conditions of service. IEP notes that the existence of competitive pressures would nonetheless benefit customers and California.
 - B. The experiences of the past year have demonstrated the importance of offering EG customers firm transportation service at reasonable terms. If EG customers had been forced to rely on interruptible gas service, due to onerous terms of firm service, blackouts would have almost certainly been unavoidable. Also, because of environmental constraints on alternate fuel use, reliable power generation from gasfired power plants requires reliable gas transportation service.
 - C. The Sempra recommendation would severely restrict the options and choices available to EG customers. Sempra's proposed requirement for 15-year commitment to specific monthly quantities as a prerequisite for firm service would force EG customers to choose between accepting these onerous terms or seeking full requirements arrangement with competing suppliers (if any provide transportation service to the particular location of the generating plant). IEP contends that they encourage Sempra gas utilities to focus their efforts on offering a broader menu of service options to their EG customers, rather than on requiring an impractical 15-year commitment.
- IEP commented that they feel Sempra's recommendation would introduce great uncertainty and create tremendous turmoil in both the natural gas and electricity markets. For these reasons, IEP respectfully urges the Energy Commission not to adopt Sempra's recommendation concerning required long-term commitments for firm service to EG customers.

Duke Energy North America (DENA) Comments

- 1. General Comments: DENA comments that in view of Sempra's August 21, 2001, letter conveying their comments and recommendations DENA feels compelled to address the severe implications Sempra's recommendation regarding the requirement of long term commitments have for the integrity of California's natural gas infrastructure.
 - DENA, in prior hearings before the CPUC, has opposed Sempra's proposal to increase long-term commitment contracts for firm transportation service from two years to 15 years, and is disturbed to find that it has surfaced before the Energy Commission.

- DENA finds this proposal to be profoundly anti-competitive and discriminatory with respect to electric generation (EG) customers, who make up the largest gas transportation customers in the State, and other noncore customers who typically have lower gas demand.
- DENA contends that if Sempra's proposal were adopted, it would lock up
 the bulk of the California gas transportation market for 15 years, effectively
 killing intrastate gas transportation competition, and realistic gas-on-gas
 competition. DENA believes it is critically important that competitive
 pressures on the price of gas transportation be maintained and enhanced
 through expanded service options.
- DENA commented that the experiences of the past year demonstrate the importance of offering EG customers firm transportation service at reasonable terms, as commitments of such long terms places an onerous, and unrealistic, business risk on EG customers. This proposal, apparently, also lacks any proposed ability to trade rights to transportation capacity, which, if Sempra is adamant about super long-term contracts, should include acknowledgement of an effective ownership interest in that transportation on the part of the customer.
- DENA recommends that Sempra's proposal be disregarded, and that Sempra gas utilities seek to expand service options to EG customers.

APPENDIX D SUMMER 2001 SUPPLY & DEMAND ANALYSIS

To assess potential demand for natural gas for the year 2001, the Energy Commission prepared a monthly natural gas demand forecast for the natural gas utility service areas. The forecast extends from May 2001 through December 2001. It includes core, noncore and electric generation. Two scenarios were developed to analyze policy alternatives. The first is a base case that reflects average summer temperature conditions. The second is a high gas use case that assumes a hotter than average summer, resulting in increased demand for natural gas by electric generators.

ASSUMPTIONS FOR NATURAL GAS & ELECTRICITY ASSESSMENT

The residential, commercial and industrial demand forecasts for each of the natural gas service areas were derived from the Energy Commission staff forecast published in June 2000.⁴² For the purposes of this analysis, residential and commercial were considered core and industrial was considered noncore.

An average of 350 MMcfd in deliveries to the SoCal Gas Service area at Wheeler Ridge was added to the PG&E demand. This 350 MMcfd reflects PG&E's contractual commitments with natural gas marketers to transport gas across its system to the SoCal Gas system.

The electric generator gas demand was estimated using the following assumptions. The electrical and natural gas demand for residential, commercial and industrial customers for each of the natural gas service areas was derived from the Energy Commission staff forecast published in June 2000. The June 2000 forecast assumes average weather conditions for 2001 for non electric generation demand. Comparisons between forecasts and historical experience may be affected by differences between average and actual weather conditions.

The electric resources available in the base case assume hydro conditions based on estimates made in March 2001 regarding snow pack and rainfall expected for the remainder of the season, one unit at San Onofre Nuclear Generating Station (SONGS) out until mid-June, and no gas fired plants shut down for air emission control retrofits this year.

The resources available in the high gas use case assume that hydroelectric output in California and British Columbia is less than the base case. In addition,

⁴² California Energy Commission Staff Report, *California Energy Demand 2000-2010*, June 2000, #P200-00-002

3,000 MW and 1,500 MW of QF capacity is off line between April 1 through May 30 and June 1 through December 31, respectively. Finally, the ISO schedule for air emission control retrofits is assumed.

PACIFIC GAS AND ELECTRIC ASSESSMENT

There are three operational issues facing natural gas storage in the PG&E service area. They are financial, physical and deregulation.

The preliminary staff analysis indicates that PG&E should have enough pipeline capacity between April 1 and October 31 to inject gas to meet the storage needs of the core and noncore sectors. Based on the Energy Commission's monthly analysis, the storage injection could be at a lower rate and still meet core storage targets.

Monthly Analysis

Figure D-1 shows the monthly natural gas demand by sector in the PG&E service area. PG&E's 3,200 MMcfd supply capacity is also shown on the figure, which consists of California production and pipeline capacity to receive natural gas from interstate pipelines. In the winter months, the supply capacity dips due to upstream demands in the Pacific Northwest that reduce the ability to deliver natural gas to California.

Residential and small commercial and industrial customers are included in the core sector. Noncore comprises the large commercial and industrial customers. PG&E also provides off-system deliveries to SoCal Gas at Wheeler Ridge. All the electric generation is included in the electric generation demand forecast.

The area under the supply capacity indicates the opportunities to place natural gas in underground storage facilities. The plot indicates the probability will be high that pipeline capacity will be available for storing natural gas.

Figure D-1 indicates that over 500 MMcfd of pipeline capacity is projected to be available in the base case to provide supplies of gas for injection into storage. Thus, even in the high gas use case, it should be physically possible for PG&E to store over 90 Bcf of gas for the winter of 2001-02.

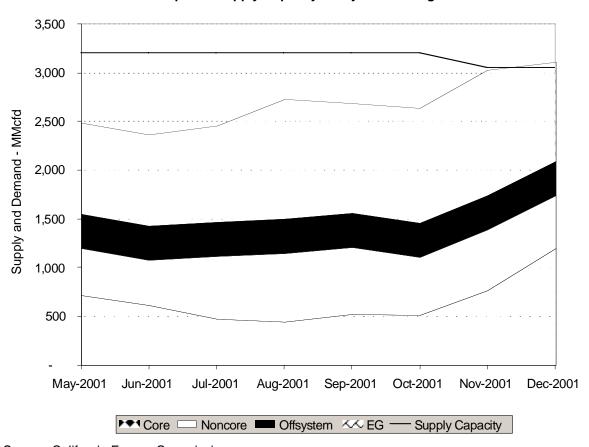


Figure D-1
PG&E Demand and Pipeline Supply Capacity – May 2001 Though December 2001

Source: California Energy Commission

To test the sensitivity of these results, a high gas use case scenario was calculated. **Figure D-2** compares the estimated natural gas demands by electric generators served by PG&E under the base case and high gas use scenarios. As the figure shows, during the summer months, gas usage by electric generators could be 25 percent higher than the base case. The dramatic decline in gas consumption in October 2000 reflects high maintenance outages for gas fired generators and increased reliance on hydro resources and high maintenance outages for gas-fired generators. The Figure also shows that during the summer months, electric generation demand in the base case is similar and possibly a little lower than that experienced in 2000.

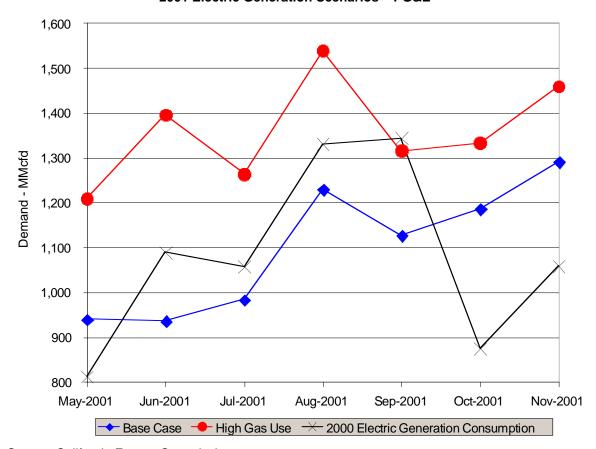


Figure D-2.
2001 Electric Generation Scenarios – PG&E

Source: California Energy Commission

By October 31, 2001, PG&E needs to place 33 billion cubic feet (Bcf) in storage for its core customers. Of the 98 Bcf of usable storage, about 53 Bcf may not be available annually. Therefore, to meet core storage needs, the total storage level shown on **Figure D-3** would have to be in the area of 86 Bcf. **Figure D-3** indicates that, assuming a 250 MMcfd injection rate, PG&E will be able to physically reach its core storage level by mid September. The figure also indicates that, even in the high gas use scenario, PG&E will still be able to meet 2001 core and electric generation needs for storage. This scenario assumes that noncore customers actually inject gas into storage. PG&E has reported that noncore injection levels are ahead of 2000.

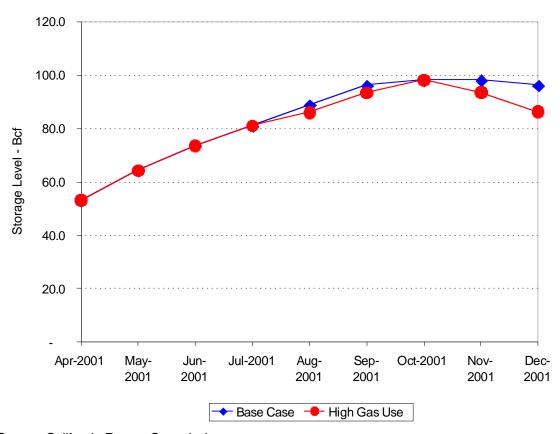


Figure D-3.
PG&E End of Month Storage Levels – April 2001 through December 2001

Source: California Energy Commission

Although PG&E appears to have the physical ability to meet noncore customer storage needs, financial questions cloud the picture. On April 6, 2001, PG&E filed for Chapter 11 reorganization in federal bankruptcy court. Despite its financial situation, PG&E has been successful injecting sufficient gas into storage throughout the summer season to meet expected winter demand.

PG&E is required to store gas to meet the needs of core customers in the winter. Because of deregulation, noncore customers have the freedom to elect to pay for the storage of gas. They may use either PG&E's storage facility or a private storage facility.

In the summer of 2000, electric generators elected not to fully utilize the PG&E storage capacity available to them. This decision by the electric generators (not to fully use available storage in the summer of 2000) put pressure on the natural gas infrastructure in the winter of 2000-01 and contributed to higher prices of natural gas for all consumers in California. If the winter of 2000-01 had been slightly more severe, the failure of the noncore customers, such as the electric generators, to store gas could have led to curtailments during the latter months.

The operator of the Wild Goose facility reports that space in its storage facility is completely subscribed for this summer. Continuing to monitor noncore customer usage of the Wild Goose and PG&E storage facilities is warranted, especially for electric generators.

SOUTHERN CALIFORNIA GAS ASSESSMENT

Two operational issues face natural gas storage in the SoCal Gas service area. They are physical and deregulation.

Earlier in the year, SoCal Gas appeared to have a problem getting sufficient natural gas into storage due to the lack of physical space in its pipelines. Since the early analysis was performed, SoCal Gas has made use of all the available slack capacity in its pipelines to inject natural gas into storage. By early July, the utility had over 70 Bcf in storage, with about 70 percent reserved for core customers. The staff's analysis now indicates that SoCal Gas should be able to meet its injection goals for the winter storage needs of both the core and noncore sectors.

Monthly Analysis

Figure D-4 shows the monthly natural gas demand by sector in the SoCal Gas service area, which includes service to SDG&E and to the Mexican power plant at Rosarito Beach. SoCal Gas has the firm capacity to receive 3,500 MMcfd, consisting of California production and pipeline capacity from several interstate pipelines, and PG&E. If the interstate pipelines are able to maintain high delivery pressures, SoCal Gas is able to receive in excess of 3,700 MMcfd. That has been the case for much of the time since March. Additional capacity to receive gas (that SoCal Gas is proposing to add) will not be available until the December 2001 timeframe.

Other actions will strengthen the utility's supply situation for the remainder of the year and into the winter 2002. SoCal Gas has received the CPUC's approval to abandon its Montebello storage field. There is about 24 Bcf in cushion gas still in the field from which 10 Bcf will be withdrawn over the next year at the rate of 90 MMcfd to augment natural gas supplies. Additionally, SoCal Gas will be converting 14 Bcf of cushion gas in its La Goleta and Aliso Canyon storage fields to working gas. Together, these actions will add 24 Bcf in natural gas supply for the remainder of the year and the winter of 2001-2002.

In **Figure D-4**, residential and small commercial and industrial customers are included in the core sector. Noncore is comprised of the large commercial and industrial customers. All the electric generation is included in the electric generation demand forecast.

The area under the supply capacity indicates the opportunities to place natural gas in underground storage facilities. The plot indicates a high probability that

there will be just barely enough pipeline capacity available for storing natural gas for winter 2002.

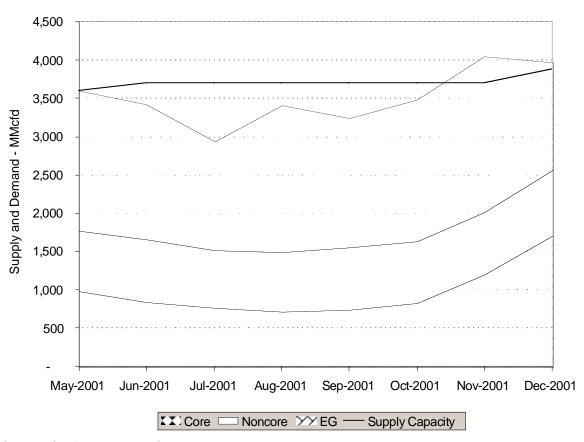


Figure D-4
SoCal Gas Demand and Pipeline Supply Capacity – May 2001 though December 2001

Source: California Energy Commission

Figure D-4 forecasts high natural gas demand for the Southern California region throughout 2001. During the summer months, SoCal Gas should be able to store the natural gas needed by the core and noncore customers for the winter. During the winter months, gas from storage will be needed to meet the core heating needs and to prevent curtailment of electric generators on the coldest days of winter.

To test the sensitivity of these results, a high gas use scenario was calculated. **Figure D-5** shows the comparison of the estimated natural gas demands by electric generators served by SoCal Gas (includes SDG&E and Rosarito Beach) under the base case high gas use scenarios. The monthly electric generation gas consumption has also been placed on the figure. As the figure shows, during the 2001 summer months gas usage by electric generators could be over 25 percent higher than the base case. In comparison to 2000, the forecasted base case monthly gas demand for power plants this year shows lower demand for the summer months, but higher during the rest of 2001. The dramatic decline

in gas consumption in September and October 2000 reflects high maintenance outages for gas-fired generators and increased use of hydro resources. (PG&E experienced similar trends in the decline of natural gas consumption for electric generators during this period.) In the high gas demand case, power plant demand for natural gas would be higher than last year for nearly all months.

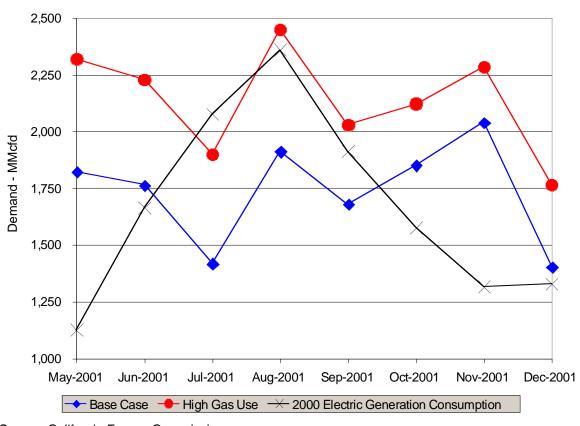


Figure D-5
2001 Electric Generation Scenarios – SoCal Gas

Source: California Energy Commission

SoCal Gas has more flexibility than PG&E to meet its core storage requirements. At 800 MMcfd, its injection capacity is considerably higher than PG&E's. At the core injection allocation of 327 MMcfd, it would take 214 days to place core's 70 Bcf into SoCal Gas's storage facilities. This is the length of time between April 1 and October 31. However, to accelerate the process of reaching the core target, SoCal Gas can inject more than 327 MMcfd whenever the noncore customers are not using their full allocation.

SoCal Gas and PG&E have nearly the same capacity to receive gas into their service areas. But SoCal Gas has nearly twice as much in-place gas-fired generation as PG&E. This higher demand caused SoCal Gas's natural gas supply receiving capability to operate at or near capacity since the early part of the 2000 summer. To meet its winter injection goals, as well as its customer

supply needs, the SoCal Gas system will need to continue to operate at or near its full capacity for the remainder of the year.

Figure D-6 presents the staff's forecasted storage levels under the base and high natural gas demand cases. It also shows the actual storage level as of July 2001. SoCal Gas storage is consistent with the base case forecast.

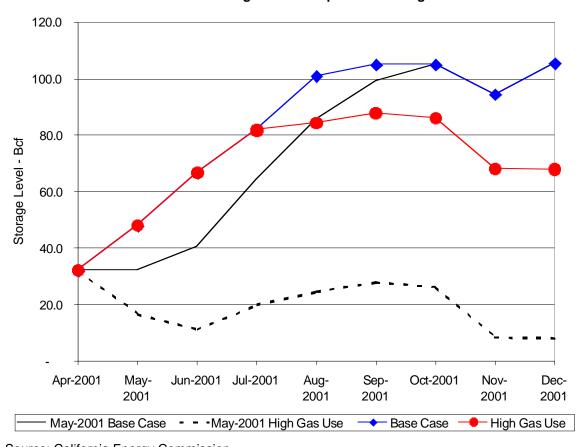


Figure D-6
SoCal Gas End of Month Storage Levels – April 2001 through December 2001

Source: California Energy Commission

The current Energy Commission base case analysis indicates that SoCal Gas will be able to completely fill its storage fields by the winter heating season. This analysis assumes that SoCal Gas and the noncore customers fully utilize spare pipeline capacity to maximize storage injections. Because of partial deregulation that SoCal Gas system operates under, noncore customers who have elected to purchase their own gas must decide whether they will use the available storage. The utility indicates that core and noncore injections have been proportional to the contracted inventory capacity of roughly 70 percent for core and 30 percent for noncore.

As **Figure D-6** indicates, SoCal Gas will have sufficient gas in storage on November 1, 2001. SoCal Gas should be able to meet its core needs for the

winter, particularly with the new receiving capacity that will be operational in December, and the 24 Bcf in additional storage production that is available from Montebello, La Goleta, and Aliso Canyon storage fields. SoCal Gas is in very good shape to meet all of its customers demands for natural gas during the coming winter heating season.

SDG&E SERVICE AREA ASSESSMENT

Monthly Analysis

Figure D-7 shows the monthly natural gas demand by sector in the SDG&E service area. SoCal Gas delivers all the supply to SDG&E, including service to the Mexican power plant at Rosarito Beach. SDG&E currently has firm capacity to receive 595 MMcfd. This was increased by 70 MMcfd in late June when SoCal Gas completed its Line 6900 upgrade.

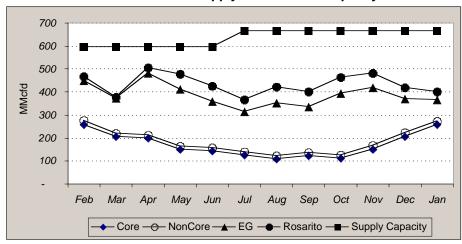


Figure D-7
SDG&E Demand Supply and Demand Capacity

Source: California Energy Commission

On a monthly average basis, there would be sufficient supply to meet the natural gas demand. There is no underground natural gas storage available in the service area.